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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
REGARDING MARKET PRICE BENCHMARKS**

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On behalf of
California Community Choice Association

May 12, 2022

SUMMARY OF RECOMMENDATIONS

- ✓ The Alliance for Retail Energy Market's Opening Comments should be rejected as they over-emphasize the risk of illiquidity and will result in an inaccurate Renewables Portfolio Standard (RPS) Adder.
- ✓ The Commission should adopt Energy Division Staff's Plan to exclude the RPS Voluntary Allocations when calculating the RPS Market Price Benchmark (MPB).
- ✓ The Commission should monitor the liquidity of the bi-lateral RPS market to ensure a stable RPS MPB.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
REGARDING MARKET PRICE BENCHMARKS

The California Community Choice Association[1] (CalCCA) submits these Reply Comments to the April 28, 2022 Comments of the Alliance for Retail Energy Markets (AReM) on *Administrative Law Judge's Ruling Regarding Market Price Benchmarks*,[2] issued April 18, 2022 (Ruling). For the reasons set forth below, the Commission should reject AReM's request to include Voluntary Allocation transactions in the calculation of the Renewables Portfolio Standard (RPS) Adder component of the Market Price Benchmark (MPB).

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] R.17-06-026, *Comments of the Alliance for Retail Energy Markets on Ruling Requesting Renewable Portfolio Standard Market Price Benchmark (MPB) Calculation* (April 28, 2022) (AReM Opening Comments) at 2.

I. THE COMMISSION SHOULD REJECT AREM'S REQUEST TO INCLUDE VOLUNTARY ALLOCATIONS IN THE CALCULATION OF THE MPB

AReM's request to include Voluntary Allocation transactions in the calculation of the RPS Adder component of the MPB places unnecessary emphasis on the dangers of market illiquidity and should be rejected. [3] In Opening Comments, both AReM and CalCCA recognize the potential risk that the Voluntary Allocations pose to the Commission's framework for calculating the RPS Adder. In years in which most load-serving entities (LSEs) are motivated to take their Voluntary Allocations instead of seeking a lower price in subsequent solicitations, *i.e.,* when market prices are rising, there is a potential for there to be few bi-lateral transactions outside of the Voluntary Allocations.[4]

AReM overstates this liquidity problem, however, when it suggests the Commission's market framework is already illiquid, lists certain transactions that are excluded, and suggests the allocations will only exacerbate the issue.[5] Little evidence exists to suggest the current market is illiquid, and evidence in other Commission proceedings suggest otherwise. For example, utility testimony supporting the IOUs' Energy Resource Recovery Account (ERRA) compliance application list many transactions between the utilities and other LSEs for RPS attributes.[6] Numerous other transactions take place each year between LSEs that are not a part of those filings. While the Commission has not adopted a bright-line definition of what constitutes illiquidity, it is far from clear that the current framework suffers from a liquidity problem.

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[3] R.17-06-026, *Comments of The Alliance For Retail Energy Markets On Ruling Requesting Renewable Portfolio Standard Market Price Benchmark (MPB) Calculation* (April 28, 2022) (AReM Opening Comments) at 2.

[4] R.17-06-026, *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Regarding Market Price Benchmarks*, (April 28, 2022) (CalCCA Opening Comments) at 4.

[5] AReM Opening Comments at 2-3.

[6] *See, e.g.*, A.22-04-001, Exh. SCE-03 at 93, Table II-23 ("New RPS Contracts Executed January 1, 2021-December 31, 2021").

In contrast to this potential liquidity problem, including the Voluntary Allocations when calculating the MPB is likely to be problematic. As the Staff Plan recognizes, including Voluntary Allocation transactions may create a persistency issue where prices from older transactions continue to influence the MPB. Because the allocations are valued at the prior year's MPB, which includes market transactions from Q1-3 of year "n-2" and Q4 of year "n-3", the value of these older transactions will "persist" in the MPB. Such a result is contrary to D.19-10-001, which focuses on more recent transactions, *i.e.*, Q1-3 of year "n-1" and Q4 of year "n-2" when calculating the RPS Adder.[7] It is not difficult to envision a scenario where LSEs are motivated to only take their allocations when RPS prices are rising, leading to an artificially depressed RPS Adder.

AReM's concern is valid, but its solution is riskier than the problem it aims to solve. A better approach is to exclude the Voluntary Allocations from the MPB and monitor the liquidity of the bilateral RPS market to ensure a stable RPS Adder.[8]

[7] D.19-10-001, Ordering Paragraph 1 and Attachment A, Table II (including the following transactions in the forecast RPS Adder: "Transactions executed in Q4 of year (n-2) and Q1-3 of year (n-1) for delivery in year n").

[8] CalCCA Opening Comments at 4.

II. CONCLUSION

For all of the foregoing reasons, CalCCA supports the Staff Plan and looks forward to an ongoing dialogue with the Commission and stakeholders with regard to ensuring liquidity in the RPS market post Voluntary Allocation implementation.

Respectfully submitted,

Tim Lindl
KEYES & FOX LLP

On behalf of
California Community Choice Association

May 12, 2022

DOCKETED

Docket Number:	22-IEPR-02
Project Title:	California Planning Library
TN #:	243118
Document Title:	California Community Choice Association Comments - One IEPR Commissioner Workshop on the California Planning Library
Description:	N/A
Filer:	System
Organization:	California Community Choice Association
Submitter Role:	Public
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Comment Received From: California Community Choice Association
Submitted On: 5/17/2022
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One IEPR Commissioner Workshop on the California Planning Library

Additional submitted attachment is included below.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON THE CALIFORNIA PLANNING LIBRARY
April 27, 2022

Docket 22-IEPR-02
California Planning Library

The California Community Choice Association (CalCCA)[1] submits these comments as a follow-up to the *IEPR Commissioner Workshop on the California Planning Library* (the "Workshop"), conducted on April 27, 2022. CalCCA was one of the panelists at the Workshop, where it gave a high-level description of its requests.[2] The purpose of these comments is to give additional detail, context, and justifications for the requests CalCCA made at the workshop.

I. THE CALIFORNIA ENERGY COMMISSION (COMMISSION) SHOULD CREATE A SINGLE LOCATION TO ACCESS IMPORTANT DATA, ORGANIZED BY SUBJECT RATHER THAN REGULATORY PROCEEDING

The current Integrated Energy Policy Report (IEPR) process produces invaluable data for all stakeholders in the electric system planning process; including hourly electric load forecasts,[3] utility resource plans,[4] and a forecast of natural gas prices.[5] However, these data are currently organized by proceeding docket, and can be difficult to find if a stakeholder is not doing the time-

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Located at : https://efiling.energy.ca.gov/GetDocument.aspx?tn=242816&DocumentContentId=76380

3 Located at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-IEPR-03

4 Located at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-IEPR-02

5 Located at https://efiling.energy.ca.gov/GetDocument.aspx?tn=239648&DocumentContentId=73062

consuming work of actively monitoring those proceedings. Therefore, the Commission should create a single location that stakeholders can use to access the data, organized first by subject, then by specific item, and then by regulatory proceeding. This approach also minimizes regulatory burden, as it merely asks the Commission to compile and maintain a list of existing links to data. An example follows below.

Subject	***Specific Item***	***Proceeding***	***Link***
Electric Load Forecast	Hourly load forecast to 2030	21-IEPR-03	https://efiling.energy.ca.gov/GetDocument.aspx?tn=241174&DocumentContentId=75019
Electric Supply Plans	LSE supply plans (Form S-2)	21-IEPR-02	https://efiling.energy.ca.gov/GetDocument.aspx?tn=239865&DocumentContentId=73307
Natural Gas Price Forecast	2021 IEPR preliminary burner-tip model	21-IEPR-05	https://efiling.energy.ca.gov/GetDocument.aspx?tn=239648&DocumentContentId=73062

In addition to the specific data items shown above, a table such as this could be accompanied by "release notes" that give a short description of the reasons for substantial changes in forecasts from version to version (for example, anomalous weather or an unforeseen decrease in economic output).

II. THE COMMISSION SHOULD PROVIDE DATA AND METHODOLOGY FOR THE "BUILDUP" PROCESS BY WHICH IT CONVERTS LOAD-SERVING ENTITY (LSE) -SUBMITTED ANNUAL LOAD MODIFIERS (SUCH AS BEHIND-THE-METER (BTM) RESOURCES, ENERGY EFFICIENCY, AND ELECTRIC VEHICLE (EV) CHARGING) QUANTITIES INTO HOURLY PROFILES IN THE IEPR LOAD FORECAST

As part of the IEPR process, LSEs submit estimated *annual* impacts of demand modifiers such as behind-the-meter photovoltaic solar (BTMPV), behind-the-meter battery storage, energy efficiency, EVs, demand response, and building electrification.[6] The Commission then aggregates and analyzes this information to convert these annual impacts into its hourly California Energy

[6] This information is contained in IEPR Form 3. The 2021 IEPR forms are located at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=237369&DocumentContentId=70555

Demand forecasts of the production of these resources.[7] Presumably, the Commission uses an assumed hourly shape for the dispatch of these resources, but currently stakeholders have little visibility into what these shapes are and how they were developed. LSEs would find these shapes immensely useful for their resource plans and performing grid reliability modeling. Thus, the Commission should make them public at the most granular level possible under confidentiality rules.

III. THE COMMISSION SHOULD PROVIDE NARRATIVE DESCRIPTION, DATA ANALYSIS CODE, AND UNDERLYING DATA SHOWING THE BUILDUP OF ITS LOAD FORECAST

Currently, the Commission develops its hourly load forecasts using a combination of input data on weather, population growth, economic growth, and assumptions on penetrations of BTM resources. While some of the details of these processes are publicly available,[8] all stakeholders would benefit from increased visibility into the process by which this input data is converted to a forecast. CalCCA requests that the Commission make at least the list below public, so that stakeholders can benefit from the substantial work that the Commission has already completed:

- Historical and forecast data on weather, including:
  - Heating Degree Days
  - Cooling Degree Days
  - outdoor air temperature
  - dew point
  - precipitation
  - windspeed
  - wind direction
  - total sky cover
  - mean sea level pressure

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[7] Hourly forecasts are located at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-IEPR-03

[8] "Hourly Load Model" presentation from December 2, 2019. Located at https://efiling.energy.ca.gov/GetDocument.aspx?tn=230924&DocumentContentId=62563

- The individual simulated hourly load ratios associated with each year of weather data that the Commission uses to calculate its 1-in-2, 1-in-10, and 1-in-30 scenarios.[9]
- Population growth estimates.
- Economic growth estimates.
- Other input data, analysis code, and outputs used in the Hourly Load Model process, to the extent it is based on public information.

There are two main benefits to releasing data such as these. First, a shared understanding of the effects of weather on load is invaluable for stakeholders to help perform electric system planning given climate change, which is a stated goal of all California regulatory agencies.[10] For example, it could help inform LSEs' own estimates of their load if they understood how weather-related load spikes are increasing over time. Second, it is especially important as processes such as Integrated Resource Planning extend the planning horizon out to 2035, which intensifies the effects of climate change.[11]

IV. THE COMMISSION SHOULD PUBLICLY POST ITS PLEXOS MODEL TO ALLOW ALL STAKEHOLDERS TO VALIDATE THE RESULTS OF THEIR OWN MODELING AND ENSURE CONSISTENCY IN INPUTS AND ASSUMPTIONS

The Commission performs crucial analysis of system reliability with its PLEXOS modeling in the California Reliability Outlook,[12] in which it runs the PLEXOS model to evaluate reliability

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9 Hourly Load Model at 5.

10 Final 2021 Integrated Energy Policy Report Volume II Ensuring Reliability in a Changing Climate. "The CEC should invest in applied research that supports integration of climate considerations into electric planning, operations, and technology investment. This integration includes improving characterization of the climate conditions under which the grid must reliably operate now and in the future, improving supply and demand forecasting over a range of timescales, and improving situational awareness and forecasting of wildfire-related risks to grid operations." Located at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241358, at 87.

11 *Administrative Law Judge's Ruling Establishing Process For Finalizing Load Forecasts And Greenhouse Gas Emissions Benchmarks For 2022 Integrated Resource Plan Filings* at 1. Located at: https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=469615281

12 California Energy Commission Staff Report: Midterm Reliability Analysis at A-2. Located at: https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf

in 2023-2026. It also uses PLEXOS in the IEPR process. While the model is technically publicly available, it is not easily found on the Commission's website. The Commission could, like the California Independent System Operator (CAISO)[13], publicly post a periodically-updated version of its model to give stakeholders visibility into the process and provide feedback. The updates should come with release notes that explain major changes to the database, including fuel price inputs, transmission limits, and generator retirements/additions.

V. CONCLUSION

CalCCA thanks the Commission for its leadership on the California Planning Library, and looks forward to further collaboration on this topic.

Date: May 17, 2022

<u>/s/ Eric Little</u>

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[13] The CAISO's PLEXOS model is located under "Special Reports," located at http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx

DOCKETED

Docket Number:	21-ESR-01
Project Title:	Energy System Reliability
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE STAFF WORKSHOP ON SUMMER AND MIDTERM RELIABILITY May 20, 2022

Docket 21-ESR-01 Energy System Reliability

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA)[1] submits these comments on the *Staff Workshop on Summer and Midterm Reliability (*Workshop), conducted on May 20, 2022. CalCCA appreciates the informative presentations by California Energy Commission (Commission) staff and other parties regarding the summer stack analysis, the Tracking Energy Development (TED) task force, supply chain impacts on new projects, and interconnection issues. The Stack Analysis[2] presented by Commission staff provides useful data points regarding the ability of the expected resource fleet to meet load under specific "average" and "extreme" conditions. The usefulness of the Stack Analysis, however, is limited without an updated Planning Reserve Margin (PRM) to inform the level of reliability the stack is attempting to meet. For this reason, CalCCA urges the Commission and other state agencies to perform an updated loss-of-load expectation (LOLE) study as soon as possible and avoid informing procurement decisions on

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] https://efiling.energy.ca.gov/GetDocument.aspx?tn=243173&DocumentContentId=76874

the 22.5 percent PRM until the level of reliability met by this standard can be validated through the LOLE analysis and vetted with stakeholders. The level of PRM and amount of new contingency measures should be established in the context of the level of reliability each provides, and the costs associated with achieving that standard. With this in mind, CalCCA makes the following recommendations:

- Stack analyses inform a snapshot in time under specific scenarios, but should not be relied upon to set procurement targets;
- The Commission should base the "average" and "extreme" cases used in a stack analysis on an updated LOLE study to ensure the stack analysis targets the level of reliability planned for in the PRM;
- The Commission should provide further information regarding the magnitude of the contingency events' estimated impact on energy reliability; and
- The Commission should clarify assumptions used in the Stack Analysis.

II. COMMENTS

A. Stack Analyses Inform a Snapshot in Time Under Specific Scenarios, but Should not be Relied Upon to set Procurement Targets

The Stack Analysis presented by the Commission provides useful information about potential summer reliability risks under a specific set of load and resource conditions. However, this work cannot take the place of traditional reliability modeling used to set procurement targets. Stack analyses cannot account for uncertainty about supply, demand, weather, renewable generation, and the complexities of storage dispatch because stack analyses by their nature only provide a single-point estimate of capacity sufficiency. LOLE models capture the complexities of actual system operation and can model many different scenarios. This gives a much better picture of actual risk and provides more accurate metrics about the probability of a resource shortfall in any given hour, which is crucial information for decision-making. For these reasons, the Commission and other state agencies should reserve the use of stack analyses as information only to demonstrate potential reliability risks and focus efforts on LOLE analysis to determine the appropriate level of PRM to ensure the resource fleet can meet a defined reliability standard (*e.g.*, 1 event-in-10 years).

B. The Commission Should Base the "Average" and "Extreme" Cases Used in a Stack Analysis on an Updated LOLE Study to Ensure the Stack Analysis Targets the Level of Reliability Planned for in the PRM

Without up-to-date LOLE modeling, it is not clear the target level of reliability the resource stack is measured against in the "average" or "extreme" cases. The 15 percent PRM was originally set by the California Public Utilities Commission (CPUC) in Decision (D.) 04-01-050 and has not been revised since then.[3] Since D.04-01-050 was adopted in 2004, the load and resource mix has changed significantly, and it is not clear that 15 percent is still the appropriate metric to use. In the Proposed Decision[4] in the Resource Adequacy (RA) proceeding, the CPUC proposed to increase the PRM to 16 percent in 2023, and 17 percent in 2024. The Proposed Decision, however, notes that additional work is needed in the Integrated Resource Plan (IRP) proceeding to base the PRM on LOLE modeling. Within the CPUC IRP proceeding, the resulting LOLEs were significantly lower than a 1-in-10 reliability standard when the 22.5 percent PRM was used in the Preferred System Plan.[5] Before addressing gaps between the resource stack and the 22.5 percent PRM through additional procurement orders, the Commission and other state agencies must first determine the targeted level of reliability the state should plan for (*e.g.*, 1-in-10 or something else).

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3 CPUC D.04-01-050: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/33625.PDF

4 See CPUC Proposed Decision Adopting Local Capacity Obligations For 2023 - 2025, Flexible Capacity Obligations For 2023, And Reform Track Framework, R.21-10-002 (May 20, 2022), at 20-22: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M478/K084/478084163.PDF

5 CPUC D.22-02-044: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

C. The Commission Should Provide Further Information Regarding the Magnitude of the Contingency Events' Estimated Impact on Energy Reliability

In the Reliability Workshop Overview presentation, Energy Assessments Division staff provided an estimate of resources available to respond to contingency events that fall outside of traditional planning targets.[6] These events include a lag in the incorporation of updated demand forecasts and policy goals in the traditional planning metrics, extreme weather and fire risks, and project delays. The presentation indicates there is a risk of needing roughly 7,000 megawatts (MW) and 10,000 MW should these contingency events happen simultaneously, while the contingency measures available equate to only roughly 2,000 MW. The presentation and discussion in the workshop frame these events as partially or fully beyond what is captured in traditional 1-in-10 planning standards.

Traditional planning standards that should be used to derive the PRM, such as the 1-in-10 planning standard, represent the state's risk tolerance to electricity outages (*e.g.*, 1 outage in 10 years). This target should be chosen balancing both reliability and affordability objectives, as increasing the PRM lowers reliability risk but also increases procurement costs that are ultimately borne by ratepayers. This same balance should be considered when evaluating contingency events and mitigating measures. Further discussion is required to establish a methodical approach for planning for contingencies beyond the 1-in-10 planning standard that balances both reliability and affordability. To advance this discussion, more information is needed to determine the full magnitude of potential contingency events, including the following:

- **How does the Commission estimate extreme weather and fire risks not captured in a 1-in-10?**

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6 https://efiling.energy.ca.gov/GetDocument.aspx?tn=243171&DocumentContentId=76872

Slide 8 of the Reliability Workshop Overview presentation indicates that there could be 4,000 to 5,000 MW impact of extreme weather and fire risk to energy assets not completely captured in 1-in-10 planning efforts. The Commission should clarify how this range was derived. Specifically, how did the Commission determine what portion of risks to energy assets from extreme weather and wildfire is captured in the 1-in-10 planning standard and what portion is not? It appears the contingency numbers provided in the presentation could align with the loss of the California-Oregon Intertie (COI), a source of reliability challenges in 2021, but a number of combinations of transmission outages could also occur that fit within this range. Planning for contingencies requires an understanding of the assumptions around what is currently covered by traditional planning standards to assess the level of reliability risk that exists without taking contingency measures and the level of reliability risk that can be achieved by taking contingency measures.

- **How is the magnitude of project delays estimated (e.g., compared to the total resource stack or compared to procurement orders?)**

The Reliability Workshop Overview describes "Project Development Delay Scenarios" that impact energy reliability, ranging from 600 MW in 2022 to a range of 1,600-3,800 MW in 2025.[7] However, it is unclear how these numbers were derived and what their exact significance is. The Commission should therefore clarify the following items: First, whether these numbers are nameplate values or instead an estimated contribution to available capacity at system peak (*i.e.*, Net Qualifying Capacity). Second, the methodology for deriving these values: The Commission should confirm if they were calculated by summing up MW that would "miss" a certain online date, or another method. For example, the 600 MW in 2022 could have been calculated by first

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7 https://efiling.energy.ca.gov/GetDocument.aspx?tn=243171&DocumentContentId=76872, at 8.

taking the set of MW that was originally scheduled to be online by July 1st, and then subtracting the MW that are supposed to be online by July 1st given new "delayed" commercial operating dates (per CPUC data). Third, if the delays are relative to total procured MW or relative to the amount of procurement ordered by the CPUC in the 2019 Procurement Order and the June 2021 Midterm Reliability order. Fourth, the reason for the large range of 1,600–3,800 MW in 2025, rather than a point estimate.

D. The Commission Should Clarify the Following Assumptions Used in the Stack Analysis:

- **The unplanned outage and demand variability assumptions in the extreme case**

The Summer Stack Analysis presentation indicates the purpose of the stack analysis is to assess average and extreme conditions and inform the need for contingency measures.[8] For the average case, the Commission assumed six percent operating reserves, five percent unplanned outages, and four percent demand variability. This is generally consistent with the current PRM, which assumes six percent operating reserves and some level of unplanned outages and demand variability to total fifteen percent. For the extreme case, the Commission assumed six percent operating reserves, 7.5 percent unplanned outages, and nine percent demand variability. The Commission should clarify how it determined its assumptions around unplanned outages and demand variability. For example, for unplanned outages, did the Commission use forced outage data from the CAISO during the months of study or some other metric? For demand variability, the nine percent demand variability assumption equates to 50.5 GW of demand, which would set a new CAISO peak load record.[9] This is a much more conservative assumption than what is used

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8 https://efiling.energy.ca.gov/GetDocument.aspx?tn=243173&DocumentContentId=76874, at 2.

9 https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

in the average case, and therefore should be carefully considered before taking contingency measures to plan for this condition.

- **The 4-hour battery discharge assumption**

The stack analysis includes battery resources with a 4-hour discharge limitation, but it is not clear how their discharge is incorporated into the stack analysis, which analyzes the hours from 4 PM to 10 PM. For example, most batteries that CCAs are procuring have a duration of four hours or less,[10] and batteries are required to have 4-hour duration to qualify as RA. This does not cover the full six hours (4 PM – 10 PM) of the analysis—meaning the batteries could be depleted at critical hours. Therefore, the Commission should clarify its assumptions for how much and when the batteries are discharging. The Commission could use data from the CAISO[11] to validate their assumptions (though they should supplement these data with an assumption for non-CAISO entities, as CAISO does not cover the whole state).

- **The Commission should clarify how non-CAISO LSE data is incorporated into the analysis**

Presumably, the scope of the stack analysis is California-wide. However, the supply stack appears to be derived solely from CPUC-jurisdictional LSEs.[12] The Commission should clarify how non-CPUC jurisdictional entities' (such as publicly owned utilities') supply-side resources are factored into the analysis.

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[10] Based on an analysis of publicly available CCA Power Purchase Agreements, located at: https://cal-cca.org/wp-content/uploads/2021/11/CCA-Clean-Energy-PPAs-November-2021-2.pdf

[11] https://www.caiso.com/todaysoutlook/Pages/supply.html#section-batteries-trend

[12] https://efiling.energy.ca.gov/GetDocument.aspx?tn=243173&DocumentContentId=76874, at 10: "New resources for 2022-2023 based on procurement status forms filed with and compiled by CPUC staff. Resources for 2024-2026 based on procurement orders from 2019 and 2021 using Preferred System Plan ratios."

The Commission should publish underlying hourly data to the charts[13] included in the stack analysis, including total generation by resource type (solar, wind, battery, etc.) and hourly loads. This is similar to the data published in the last stack analysis,[14] but broken out all resource types, batteries, etc.

III. CONCLUSION

CalCCA appreciates the opportunity to comment on the workshop and looks forward to further collaboration with the Commission and stakeholders to inform future summer reliability assessments.

Date: May 27, 2022

/s/ Eric Little
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13 *Id.* at 14-21.
14 https://efiling.energy.ca.gov/GetDocument.aspx?tn=241146&DocumentContentId=74991

May 31, 2022

VIA ELECTRONIC MAIL

Mr. Simon Baker
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Re: California Community Choice Association's Protest of Pacific Gas and Electric Company's Tier 2 Advice Letters 6589-E and 6589-E-A, regarding Community Choice Aggregator (CCA) Financial Security Requirements in Compliance with D.18-05-022

Dear Mr. Baker:

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of Pacific Gas and Electric Company's (PG&E) Tier 2 Advice Letters 6589-E and 6589-E-A, regarding Community Choice Aggregator (CCA) Financial Security Requirements in Compliance with D.18-05-022 (Advice Letter). The Advice Letter seeks approval of the Financial Security Requirements (FSRs) that determine the financial security that community choice aggregators (CCAs) must post.

INTRODUCTION

PG&E's proposed FSR amounts are inconsistent with PG&E's Rule 23, and underlying Commission decisions. This inconsistency should be corrected. CalCCA requests that the Commission require PG&E to correct the period for determination of "peak load" in applying the applicable resource adequacy (RA) cost based on PG&E's own tariff.

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

2 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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.

PROTEST

PG&E's Calculation Departs From PG&E's Rule 23 and Underlying Decisions in Determining a CCA's "Peak Demand"

Rule 23.X.1 (Sheet 64) requires PG&E to calculate a CCA's monthly peak demand (MW) forecast, for purposes of determining the RA volume, "using the most recent 12 months of historical monthly peaks." PG&E's calculations, however, appear to rely on the use of the most recent six months' historical monthly peaks.[3]

PG&E's Rule 23 is consistent in its peak demand calculation with the comparable rules of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E).[4] In fact, each rule uses precisely the same language. The demand calculation articulated in PG&E's Rule 23 is also consistent with Commission Decision (D.) 18-05-022. D.18-05-022 directed the determination of the FSR consistent with the "methodology set forth in the Joint Utilities' testimony."[5] The Joint Utilities' testimony, in turn, provides: "[t]he CCA's monthly peak demand forecast (MW) will be established using the most recent calendar year of historical monthly peaks, defined as the CCA's demand during each month's system peak hour."[6]

For these reasons, the Commission should require PG&E to update the proposed FSR amounts using a peak demand based on the most recent 12 months of historical peaks.

CONCLUSION

CalCCA thanks the Energy Division for its review of this protest, and requests that the Commission require PG&E to correct the period for determination of "peak load" in applying the applicable RA cost consistent with PG&E's tariff and D.18-05-022.

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3 PG&E Advice Letter 6589-E-A, Attachment C, line 30: CCA Average Peak Demand is described as the average of column 8, lines 3 through 8. Lines 3 through 8 are the months of May through October and exclude the months of November through April, and thus are using the six months of the FSR period and not the 12 months as indicated in the tariff.

4 SCE Rule 23 section X.1, PG&E Rule 23 section X.1, and SDG&E Rule 27 section X.1 all state, "The CCA's monthly peak demand forecast (MW) will be established using the most recent [twelve] 12 months of historical monthly peaks, defined as the CCA's demand during each month's system peak hour."

5 *See* D.18-05-022 at 7.

6 *Joint Utilities' Direct Testimony Proposing a Methodology for Calculating and Implementing the CCA Financial Security Requirement*, R.03-10-003 (July 28, 2017) (JU Testimony), at 23 (emphasis supplied).

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
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On behalf of
California Community Choice Association

June 6, 2022

TABLE OF CONTENTS

I. INTRODUCTION 2

II. THE MARKET OFFERS SHOULD NOT BE SUBJECT TO BID FLOORS 4

III. THE IOUS' CODES OF CONDUCT SHOULD BE MODIFIED AND ENHANCED TO ENSURE FAIR AND NON-DISCRIMINATORY MARKET OFFER PROCESSES 6

A. Specific Modifications Should Be Made to Each of the IOUs' CoCs 8

1. SCE COC 8

2. PG&E COC 8

3. SDG&E COC 9

B. The IOUs' Consequences for Violations of the CoCs and Proposed Remedies are Insufficient and Will Not Protect the Market from IOU Misconduct 10

IV. BIDDERS' REMEDIES FOR VIOLATIONS OF MARKET OFFER PROCESS REQUIREMENTS SHOULD NOT BE WAIVED OR OTHERWISE LIMITED 11

V. SDG&E MUST REVISE ITS SOLICITATION DOCUMENTS AND SUBMIT A SUPPLEMENTAL ADVICE LETTER TO SPECIFY MARKET OFFER CONTRACT DETAILS AND A REQUIREMENT THAT IT NOTIFY BUYERS OF A CHANGE IN THE RESOURCE POOLS 13

VI. CONCLUSION 14

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.07-12-052 6
D.18-10-019 4
D.20-06-002 7
D.20-12-006 7
D.21-05-030 .... 2, 6

California Public Utilities Commision Proceedings

R.06-02-013 6
R.17-06-026 .... 2, 5
R.17-09-020 7
R.18-07-003 .... 1, 2
R.19-11-009 7

SUMMARY OF RECOMMENDATIONS

- If the investor-owned utilities (IOUs) have proposed bid floors in their redacted Confidential Market Offer process filings, such bid floors should be rejected; imposing bid floors will reduce sales opportunities and leave more "unsold" Renewables Portfolio Standard (RPS) resources in the Energy Resources Recovery Account (ERRA), thereby increasing the Power Charge Indifference Adjustment (PCIA);

- The proposed IOU Codes of Conduct (CoC) should be modified and enhanced to align with core CoC principals approved by the Commission in other contexts in which the IOUs administer solicitations in which they participate to ensure fair and non-discriminatory market offer processes;

- Any requirement that bidders waive or limit their rights for redress for any violation of the terms of the solicitation should be removed because an IOU's violation of its solicitation requirements for the Market Offer will have a long-lasting impact on the market as a whole; a simple re-solicitation, which would delay the transfer of RPS, will not resolve these issues; and

- SDG&E should be required to revise its Market Offer process and submit a Supplemental Advice Letter revising its draft Market Offer pro forma contract to: (1) require the complete and final terms of the offer to be included in the contract form or forms to be used, and (2) include a provision whereby SDG&E notifies buyers of changes to the resource pools as is required for SDG&E's Voluntary Allocation pro forma contracts.

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON MARKET OFFER PROCESS**

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Joint Filing on Track 1- Draft 2022 Renewables Portfolio Standard Procurement Plan - Market Offer Process* filed May 2, 2022 (Market Offer Process, or MO Process) by Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively, the Joint IOUs). These Comments are filed timely pursuant to the *Assigned Commissioner's Ruling and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2022 Renewables Portfolio Standard ("RPS") Procurement Plans and Denying Joint IOUs' Motion to File Advice Letter for Market Offer Process*, dated April 11, 2022, as amended by the *Administrative Law Judge's Ruling Modifying the Schedule for Track 1 of the 2022 Renewables Portfolio Standard Procurement Plan,* issued on April 21, 2022 (April 21 Ruling).

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. INTRODUCTION

The Joint IOUs' Market Offer Process filing includes several elements: (1) an overview of the proposed process; (2) each IOU's proposed solicitation protocol; (3) each IOU's proposed Code of Conduct (CoC) for solicitations in which the IOU participates as a bidder; and (4) filed separately, each IOU's "Confidential Market Offer Strategies Supporting Market Offer Process" document (Sales Strategy).[2] The Sales Strategies were filed separately pursuant to the April 21 Ruling and form part of the MO Process.[3] The MO Process, if adopted by the Commission, will govern the Market Offer portion of the Voluntary Allocation and Market Offer (VAMO) process ordered by Decision (D.) 21-05-030 (Phase 2 Decision).[4] CalCCA offers four recommendations, as noted below, aimed to maximize the benefits of the process to all parties.

First, CalCCA recommends that the Commission reject any bid floors established for the Market Offers. Significant portions of the Sales Strategies are redacted. Indeed, in the filings of both SCE and PG&E, approximately one-half of each document is completely redacted. Although any actual statements to this effect do not appear in the public versions of the Sales Strategies, CalCCA infers from the context that the Sales Strategies include each IOU's proposal to establish a bid floor for offers submitted by participants in the Market Offers.[5] Given the highly unique product and the purpose of the Market Offers, however, bid floors are

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2 *Motion of Southern California Edison Company (U-338-E) for Leave to File its Confidential Appendix A to its Track 1 Draft 2022 Renewables Portfolio Standard Procurement Plan Under Seal*, R.18-07-003 (May 16, 2022) (SCE Sales Strategy); *Motion of Pacific Gas and Electric Company (U 39 E) for Leave to File Under Seal Confidential Material in Pacific Gas and Electric Company's (U 39 E) Track 1 - Draft 2022 Renewables Portfolio Standard Procurement Plan - Market Offer Process*, R.18-07-003 (May 16, 2022) (PG&E Sales Strategy); *Motion of San Diego Gas & Electric Company (U 902 E) for Leave to File Under Seal Its Market Offer Sales Framework*, R.18-07-003 (May 16, 2022) (SDG&E Sales Strategy).

3 April 21 Ruling at 2.

4 D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 24, 2021).

5 *See* SCE Sales Strategy; PG&E Sales Strategy; SDG&E Sales Strategy.

inappropriate and should be rejected. Bid floors will reduce sales and leave unsold RPS in the IOUs' portfolios, which directly contradicts the purpose of the Market Offer process.

Second, with respect to each IOU's CoC included in the MO Process, the Commission should order modifications to align the CoCs with core principles established for CoCs in previous situations involving the IOUs as participants in their own solicitations.

Third, the solicitation documents of SCE and PG&E include language by which all parties submitting bids in response to the offer agree to waive rights to any redress for any violation of the terms of the solicitation *other* than a re-solicitation. The entire VAMO process, including the solicitation protocols, CoCs, and Sales Strategies developed for use in the Market Offers, is novel and the documents are created for a specific and unique situation. The VAMO process, the result of almost a year's work in the Power Charge Indifference Adjustment (PCIA) proceeding, was ordered by the Commission to help address an imbalance in the distribution of costs in the IOUs' PCIA-eligible portfolio. Any violation of the protocols or CoCs governing the Market Offers will stymie the Commission's efforts to address this imbalance and have a wide-ranging effect on ratepayers throughout the state for years to come. The use of the waiver language in SCE's and PG&E's filing is inappropriate and the language should be deleted entirely.

Finally, SDG&E should be required to modify its Market Offer process filing and submit a Supplemental Advice Letter updating its pro forma contract to include the form or forms of the contract that will be used in the Market Offer and that specifies the product that SDG&E is offering. In addition, SDG&E should be required to include a provision in its pro forma contract (identical to the provision required by Energy Division with respect to SDG&E's Voluntary

Allocation pro forma contract) requiring it to provide notice of modifications to the resource pools.

CalCCA therefore requests that the Commission require the following:

- If the IOUs have proposed bid floors in their confidential Sales Strategies, such bid floors should be rejected as inappropriate given the highly unique product and purpose of the Market Offers;
- The proposed IOU CoCs should be modified and enhanced to align with core CoC principals approved by the Commission in other contexts in which the IOUs have bid into solicitations they administer;
- Any requirement that bidders waive or limit their rights for redress for any violation of the terms of the solicitation should be removed; and
- SDG&E should be required to revise its Market Offer process and submit a Supplemental Advice Letter revising its draft Market Offer pro forma contract to (1) require the complete and final terms of the offer to be included in the contract form or forms to be used, and (2) include a provision whereby SDG&E notifies buyers of changes to the resource pools as is required for SDG&E's Voluntary Allocation contracts.

II. THE MARKET OFFERS SHOULD NOT BE SUBJECT TO BID FLOORS

While the existence of a bid floor in the IOUs' confidential Sales Strategies is unknown, CalCCA infers from the significant redactions throughout the Sales Strategies that the IOUs are proposing bid floors for offers submitted by participants in the Market Offers. If this is the case, such bid floors should be rejected for the following reasons: (1) bid floors can prevent the sale of RPS contrary to the intent of the VAMO process; and (2) the IOUs cannot reasonably set bid floors given there is no reference market for Market Offer transactions.

The purpose of the Commission's portfolio optimization efforts under the Phase 2 Decision is to achieve a "voluntary, market-based redistribution of excess resources" in the IOUs' supply portfolios.[6] The VAMO process is the single largest portfolio optimization effort ordered under the Phase 2 Decision. Under the Market Offer process, the IOUs will offer for sale

[6] Phase 2 Decision at 10 (citing D.18-10-019 at 3).

"slices" of their PCIA-eligible RPS portfolios remaining after the completion of each IOU's Voluntary Allocation of RPS volumes to LSEs in their service territory. Thus, the Market Offers have the potential to effect real change in the distribution of RPS among California LSEs, as envisioned by the Commission.

The successful sale of RPS through the Market Offers will both increase revenue and reduce the amount of "unsold" RPS accounted for in the ERRA. Both actions potentially reduce the PCIA for all customers. However, when those resources remain "unsold," they are valued at $0 for the PCIA calculation.[7] Thus, the IOUs' failure to accept sales at below their own established bid floor – and therefore allowing the IOUs to deem the resources "unsold" – potentially deprives all customers paying the PCIA from revenue for those lost sales and prevents a potential reduction of the PCIA.

In addition, the IOUs cannot reasonably set a bid floor for the Market Offers as there is no analogous established market for the products being offered. Unlike the vast majority of RPS transactions, the Market Offer products are not firm products. These "slices" are not a fixed volume, and do not originate from a fixed set of resources. The "slices" of RPS product to be sold in the Market Offers are instead offers of whatever volumes are generated during the term of the contract. In addition, the set of resources providing the RPS energy and renewable energy credits (RECs) may decrease over time due to the IOUs' ongoing portfolio optimization efforts. Thus, the volume of RPS sold may vary greatly throughout the term of the contract, making this product riskier for buyers than a typical sale. There is no established "market" for this "slice" product – this type of product is not currently available or frequently, if ever, transacted. Thus, there is no established reference point to which a bid floor can reasonably be tied.

[7] D.19-10-001, OP 3.b. at 56.

If they propose bid floors, the IOUs will have apparently calculated that if offers for this product fall under a particular price, the RPS energy and RECs should not be sold, and should instead be retained for the IOUs' own use. In effect, the IOUs will be taking the position that the "value" of the RPS to them is greater than the bid floor they specify – if an offer comes in under the bid floor, it makes more economic sense for the IOU to retain the RPS and RECs for its own purposes. By establishing bid floors, the IOUs will insert their own "value" into a process that is intended to be market driven. Interestingly, this contradicts SCE's argument last year in which it supported what it deemed the "underlying foundation of the Phase 1 Decision (D.18-10-019) that IOU portfolio generation resources and their associated attributes only have 'value' to the extent that value can be monetized for customers in the relevant energy markets."[8] SCE's argument last year is correct in that the true "market value" for this product is determined by bidders in an actual sale, not by some unstated "value" claimed by the IOUs. For the reasons set forth above, any IOU request for bid floors for the Market Offers should be rejected.

III. THE IOUS' CODES OF CONDUCT SHOULD BE MODIFIED AND ENHANCED TO ENSURE FAIR AND NON-DISCRIMINATORY MARKET OFFER PROCESSES

The Phase 2 Decision allows the IOUs, as LSEs, to participate in Market Offer solicitations that they administer.[9] As part of its review of the Market Offer proposals, the Commission commits to considering "appropriate rules for IOU participation in Market Offers."[10] In addition, if the IOU participates in its own Market Offer, "the IOU must (i) submit bids to the [Independent Evaluator (IE)] and [Energy Division (ED)] in advance of the Market

[8] *Opening Comments of Southern California Edison Company (U 338-E) on the Proposed Decision of Administrative Law Judge Wang on Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, R.17-06-026 (April 26, 2021), at 5.

[9] D.21-05-030 at 64, OP 3(c).

[10] *Id.* at 25.

Offer launch or (ii) establish dual procurement teams separated by an ethical wall, with monitoring by the IE to ensure a fair and non-preferential process."[11] Appendix C of the Market Offer Process filing includes each IOU's proposed Market Offer CoC defining rules for its participation in Market Offer solicitations.

The Commission has previously provided guidance on necessary CoC components for an IOU's participation in its own solicitations.[12] These components are intended to protect confidential, market-sensitive information (including any non-public information that would be useful to a bidder and third-party information received by the IOU) and ensure a fair and non-preferential solicitation. Components of an effective CoC include:

- Functional separation of IOU employees conducting the solicitation from those preparing bids;
- Information technology firewalls and restrictions on access to physical files to prevent bid teams receiving confidential market-sensitive information;
- An affirmative requirement that employees involved in bids and solicitations certify that they will abide by the CoC;
- Monitoring by an IE and Procurement Review Group (PRG);

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11 *Id.*

12 *See* D.07-12-052, *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas and Electric Company's Long-Term Procurement Plans*, R.06-02-013 (Dec. 21, 2007) at 206-07, n.236 (describing the requirements for CoCs to ensure that an IOU cannot use "inside information" to its own advantage); *see also* D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program,* R.17-09-020 (June 11, 2020) at 65-66 (directing PG&E and SCE acting as Central Procurement Entities (CPEs) in the procurement of local resource adequacy "to establish a strict [CoC] to be signed by all IOU personnel involved in the RFO process to prevent sharing of sensitive information between staff involved in developing utility bids and staff who created bid evaluation criteria and selected winning bids"); *see also* D.20-12-006, *Decision on Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism and Competitive Neutrality Rules,* R.19-11-009 (Dec. 3, 2020) at 32-33 (adopting PG&E's and SCE's respective competitive neutrality procedures, and noting that each CPE will also create CoCs); *see also* PG&E Advice Letter 6386-E (Nov. 1, 2021), accepted as of April 18, 2022 (PG&E's Annual CPE Compliance Report with Independent Evaluator Report attached detailing its CPE CoC) and SCE Advice Letter 4626-E (Nov. 1, 2021), accepted as of March 10, 2022 (SCE's Annual CPE Compliance Report with Independent Evaluator Report attached detailing its CPE CoC).

- A requirement that IOU Bids be submitted prior to third-party bids; and
- Adequate consequences for violations of the CoC.[13]

As set forth below, each IOU's proposed CoCs is missing some portion of the above elements and should be modified to ensure fair and non-preferential Market Offer processes. In addition, all of the IOUs' CoCs inadequately address the consequences of violations of the CoCs, as discussed below.

A. Specific Modifications Should Be Made to Each of the IOUs' CoCs

The Commission should require the following modifications to each of the IOUs' CoCs.

1. SCE COC

SCE's CoC contains language addressing the majority of the components required in an effective CoC. However, the Commission should require the following modifications to SCE's CoC to ensure fair and non-discriminatory participation by SCE in the Market Offer:

- Section I. of SCE's CoC requires that once a solicitation launches, members of its bid solicitation team may not transfer to become members of the bid team. However, the first sentence of the second paragraph of Section I. allows a member of the Market Offer Solicitation Team (MOST) to transfer to the Market Offer Bid Team (MOBT), which should be deleted as it is inconsistent with the prior paragraph, and would inappropriately allow a member of the bid team to have knowledge of third party bid information while formulating SCE's bid; and
- The CoC should require all employees involved in the Market Offer to sign the Certification included on the last page of the Code of Conduct.

2. PG&E COC

PG&E's proposed CoC should be revised to address all of the components listed above, as follows:

- In section 6, the term of the CoC should be revised to last until one year after the approval of the last Market Offer contract;

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13 *Id.*

- PG&E should be required to submit bids to the IE and PRG prior to the submission of third-party bids;

- PG&E should adopt SCE's commitment to preventing simultaneous competing solicitations for the same products during the same delivery period by prohibiting the sale of RECs through PG&E's RPS sales program while a Market Offer solicitation is open;

- PG&E's prohibition on transfers of employees from the solicitation team to the bid team should be extended from "submission of executed contracts" to at least one year after CPUC approval of the market offer contracts;

- The CoC should state that an IE will monitor its Market Offer and compliance with the CoC;

- Section 7 should be amended to state that violations of the CoC should be disclosed in the IE Report; and

- All employees involved in the Market Offer should be required to sign the Certification included on the last page of the CoC.

3. SDG&E COC

SDG&E's CoC should be modified to:

- Require the CoC's term to last until one year after the approval of the Market Offer contracts;

- Require SDG&E to submit Market Offer bids to the IE and PRG prior to the submission of third-party bids;

- Adopt SCE's commitment to preventing simultaneous competing solicitations for the same products during the same delivery period by prohibiting the sale of RECs through SDG&E's RPS sales program while a Market Offer solicitation is open;

- Prohibit the transfer of employees from the Bid Evaluation Team (the solicitation team) to the SDG&E Front Office (the bid team) for at least one year after approval of the Market Offer contracts; and

- Include consequences for a violation of the CoC, including disclosure of that violation by SDG&E to the Commission's Energy Division, PRG and the IE, as well as discussions between SDG&E, ED, PRG and the IE regarding appropriate remedies to address the violation. Such a violation should also be disclosed in the IE Report.

B. The IOUs' Consequences for Violations of the CoCs and Proposed Remedies are Insufficient and Will Not Protect the Market from IOU Misconduct

As noted above, one of the major components of an IOU's CoC for its own solicitations is the section establishing the consequences of any breach of that CoC. None of the IOUs have included sufficient language addressing this point. Indeed, the SCE and PG&E propose nothing other than a presentation to their own IE and PRGs, and then a "discussion" with Energy Division staff.[14] SDG&E's CoC does not address violations of the CoC at all. As is examined in more detail below, the market impact of an IOU's breach of its obligations in the context of a Market Offer can have statewide, significant impacts.

The IOUs' participation in their own solicitations is one of the major characteristics that differentiates the Market Offer from "regular" RPS sales. The CoCs are necessary to enable that participation, while ensuring a fair and equitable Market Offer. A CoC without material consequences for violations does not adequately address the risk of harm that could result from misconduct. Given the importance of the Market Offer to the PCIA calculation going forward, the remedy for such a violation should not rest with the IE and PRG, as proposed by the IOUs, and should not be limited to a re-solicitation. In addition, the Market Offer process documents *must not* include a provision limiting remedies for violations of the CoCs, discussed below.

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[14] SCE proposed CoC, section J (SCE will provide notice of a CoC violation to the Commission's Energy Division, PRG and the IE, the IE will discuss the impact of the violation in its IE Report, and SCE shall consult with the ED, PRG and IE regarding appropriate remedies to address a CoC violation); PG&E proposed CoC, section 7 (PG&E will provide notice of a CoC violation to Energy Division, the PRG and the IE, and will consult with Energy Division, the PRG and the IE regarding the appropriate remedies to address a CoC violation).

IV. BIDDERS' REMEDIES FOR VIOLATIONS OF MARKET OFFER PROCESS REQUIREMENTS SHOULD NOT BE WAIVED OR OTHERWISE LIMITED

The limitations on remedies or waivers of claims for violations of the approved Market Offer processes proposed by both SCE and PG&E leave insufficient remedies available to market participants. SDG&E does not address remedies or claims for violations in its Market Offer process proposal, but the Commission should prohibit SDG&E from imposing any similar limitations on remedies or waivers of claims. Given the nature of the Market Offers and their potential impact on the PCIA as a whole, remedies for IOU violations should be significant enough to deter the prohibited behavior. In addition, because the impact of misconduct will affect the PCIA for all customers in the service territory, a remedy must also reach to all customers. Limiting the IOU's consequence to simply re-soliciting the offer is insufficient.

Section 8.3 of SCE's solicitation instructions include language regarding "waived claims."[15] Under this language, by submitting a bid in the solicitation all offerors agree that the sole means of challenging the conduct or results of the Solicitation is a complaint filed under Article 3, Complaints and Commission Investigations, of Title 20, Public Utilities and Energy, of the California Code of Regulations.[16] Bidders further agree that the exclusive remedy available to Buyer in the case of such a protest shall be an order of the Commission that SCE again conduct any portion of the Solicitation that the Commission determines was not previously conducted in accordance with these Instructions (including any associated documents), and Buyer expressly waives any and all other remedies.[17]

PG&E's solicitation instructions contain very similar language by which participants in the offer agree to seek redress only through Commission processes or a protest to the advice

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15 MO Process, Appendix B-1 at 40.
16 *Ibid*.
17 *Id*., Appendix B-1 at 41.

letter filing seeking approval of the ultimate contract or contracts.[18] Participants will also agree that the exclusive remedy available to each participant shall be an order of the Commission that PG&E again conduct any portion of the Solicitation that the Commission determines was not previously conducted in accordance with the Solicitation Protocol.[19] Participants also waive all other remedies.[20]

As noted previously, the CoCs of each of SCE and PG&E form part of the Market Offer Process. These Market Offers are not simple RPS transactions where the only injury in the case of a mishandled solicitation is to a bidder who loses the contract. In contrast, violations of the solicitation documents will affect the revenues collected by the IOUs with respect to the Market Offer as a whole, and therefore the resultant PCIA going forward. For example, failure to apply the evaluation criteria appropriately will result in either greater or lesser revenue to offset PCIA costs. More significantly, any violation of a CoC by, for example, a prohibited use of confidential, market-sensitive information, would seriously impact the market price of RPS used to calculate the PCIA, not to mention erode participants' faith in the integrity of the Market Offer process.

Limiting bidders' claims to Commission dispute resolution, or an advice letter protest, fails to provide sufficient deterrence against such potentially damaging misconduct. Because the impacts will be long-lasting and statewide, all remedies should be available, including a review of potential disallowances in the relevant ERRA Compliance Application.

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18 *Id*., Appendix B-2 at 11.

19 *Ibid*.

20 *Ibid*.

V. SDG&E MUST REVISE ITS SOLICITATION DOCUMENTS AND SUBMIT A SUPPLEMENTAL ADVICE LETTER TO SPECIFY MARKET OFFER CONTRACT DETAILS AND A REQUIREMENT THAT IT NOTIFY BUYERS OF A CHANGE IN THE RESOURCE POOLS

SDG&E should be required to not only specify the products and the contract to be used in its Market Offer, but also to include the same contract term regarding notice of modifications to the resource pool that Energy Division is requiring SDG&E to include in its Voluntary Allocation pro forma contract.

First, SDG&E's draft "Market Offer Protocols for the Sale of Renewable Energy Products" included in the Market Offer Process document[21] indicates that SDG&E may offer both long and short term sales.[22] SDG&E also provides that bidders into its Market Offer must "mark up" SDG&E's Long-form Confirmation to the Western Systems Power Pool (WSPP) agreement or Edison Electric Institute (EEI) Agreement.[23] However, the Market Offer pro forma contracts for both bundled and unbundled product SDG&E submitted to the Commission for approval are draft WSPP confirmations.[24] SDG&E must be required to specify through both a revision to its Market Offer Process filing and its Market Offer pro forma (through a Supplemental Advice Letter) the contract that will be used for the Market Offer, and the product or products that will be offered.

In addition, SDG&E should be required to include in the approved Market Offer pro forma contract a provision whereby it will inform buyers of changes to the resource pools making up the "slice" of the portfolios purchased through the Market Offer. The Draft

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21 MO Process Appendix B.3.
22 *Id.*, Appendix B.3 at 3.
23 *Id.*, Appendix B.3 at 5.
24 Advice Letter 3983-E, San Diego Gas & Electric Approval Request of Market Offer Contracts for Renewables Portfolio Standard Resources Pursuant to Decision 22-01-004, (April 4, 2022) (SDG&E Market Offer Pro Forma Advice Letter).

Resolution regarding the Voluntary Allocation pro forma contract requires SDG&E to adopt CalCCA's proposed language regarding these points in the voluntary allocation pro forma contract.[25] The same concerns apply to the Market Offer pro forma contract, and therefore SDG&E should be required to insert the following language (identical to the language required in SDG&E's Voluntary Allocation pro forma) in its Market Offer pro forma contract:

> With fifteen (15) day's prior notice to Buyer, Seller may add or remove a Resource from the Resource Pools as provided herein. Seller may remove a Resource from the Resource Pools for the following reasons: (i) if Seller's power purchase agreement corresponding to the Resource has been modified, terminated, or assigned to a third party, (ii) if the Resource is no longer in Seller's PCIA-eligible portfolio due to Commission order or direction, or (iii) if the Resource is owned by Seller but ceases operation for Seller.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these Comments on the IOUs' Market Offer process and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Evelyn Kahl

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

June 6, 2022

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25 Draft Resolution E 5216 (June 23, 2022) at 16.

June 9, 2022

VIA ELECTRONIC MAIL

Mr. Simon Baker
Interim Director, Energy and Climate Policy
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: California Community Choice Association's Comments on Draft Resolution E-5216, *Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Renewables Portfolio Standard Voluntary Allocation Pro Forma Contracts*

Dear Mr. Baker:

Pursuant to Rule 14.5 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the Comment Letter accompanying Draft Resolution 5216-E (Draft Resolution), the California Community Choice Association[1] (CalCCA) submits these comments on the Draft *Resolution E-5216. Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Renewables Portfolio Standard Voluntary Allocation Pro Forma Contracts,* dated June 23, 2022 (Draft Resolution).

CalCCA thanks the Commission for its thoughtful consideration of the issues raised by CalCCA and others with respect to the Advice Letters proposing the Renewables Portfolio Standard (RPS) Voluntary Allocation pro forma contracts, as supplemented,[2] forming the basis of the Draft Resolution. Following meetings between CalCCA and the investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) submitted supplemental Advice Letters to address many of the concerns CalCCA raised in its Protests to the original Advice Letters. Specifically, PG&E and SCE addressed: (1) allowing short-term allocations from the long-term resource pools, (2) inclusion of utility-owned

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 PG&E Advice 6517-E (Feb. 28, 2022), supplemented by PG&E Advice 6517-E-A (Apr. 11, 2022); SCE Advice 4732-E (Feb. 28, 2022), supplemented by 4732-E-A (Mar. 18, 2022), supplemented by 4732-E-B (May 17, 2022); SDG&E Advice 3962-E (Feb. 21, 2022).

generation (UOG) and evergreen contracts in long-term voluntary allocations, and (3) adding contract language regarding notice and removal of resources from the allocation pools.[3] CalCCA largely supports the Draft Resolution's conclusions and orders approving PG&E's and SCE's filings.

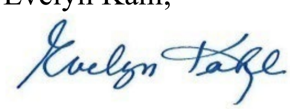
In addition, the Commission is requiring SDG&E to update its pro forma contract to address these three issues. CalCCA supports the requirement that SDG&E file a supplemental Advice Letter to modify its pro forma contract as set forth in the Draft Resolution.

CalCCA appreciates the Commission's encouragement of data sharing among IOUs and the load-serving entities (LSEs) receiving Voluntary Allocations to enhance CCA forecasting and operations. However, CalCCA is disappointed with the Draft Resolution's finding that providing preliminary forecast and meter data within 15 calendar days of the end of a Voluntary Allocation contract's Calculation Period "would be difficult, if not impossible, to provide." Certainly, providing timely access to preliminary data is *not impossible*, and critically, as discussed in CalCCA's Protests, access to such timely data is necessary to not disadvantage CCAs with regard to portfolio optimization. Simply encouraging the timely sharing of data is insufficient. The Commission should require the IOUs to provide preliminary, non-binding forecast and meter data within fifteen days of the end of the relevant delivery period.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl,



General Counsel and Director of Policy

cc via email:

Energy Division Tariff Unit (edtariffunit@cpuc.ca.gov)
christian.knierim@cpuc.ca.gov
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Service List: R.17-06-026 and R.18-07-003

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3 *See CalCCA Protest to PG&E Advice 6517-E* (Mar. 21, 2022); *CalCCA Protest of SCE Advice 4732-E* (Mar. 21, 2022); *CalCCA Protest of SDG&E Advice 3962-E* (Mar. 21, 2022).

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND REFORM TRACK FRAMEWORK

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June 9, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THE PD SHOULD BE REVISED TO ALLOW HOURLY RA TRANSACTIONS UNDER THE 24-HOUR SLICE FRAMEWORK 3

A. The 24-Hour Slice Framework Does Not Meet the Commission's First or Third Principle Without Hourly Transactions 3

B. The PD Vastly Overstates the Barriers to Hourly Trading 7

1. Hourly Obligation Trading and Hourly Resource Trading are Fundamentally Different Mechanisms and Should Not be Conflated 7

2. Hourly Resource Trading is not Unbundling and Should be Coupled With the Existing 24X7 Must Offer Obligation 7

3. The PD Overstates the Complexity Required to Allow Hourly Trading 8

4. Existing Contracts Can and Should be Preserved in a Framework With Hourly Trading 11

5. CAISO Processes can be Made Compatible With Hourly Trading 11

C. A Transactable RA Product Cannot be Achieved Through Swaps Alone 12

III. THE PD SHOULD BE MODIFIED TO ALLOCATE CAM RESOURCES TO THEIR APPLICABLE MCC BUCKET 13

IV. THE SCOPE OF WORKSTREAMS TWO AND THREE SHOULD BE MODIFIED TO CONSIDER A UCAP-LIGHT AND A FULL UCAP METHODOLOGY 14

V. CONCLUSION 15

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.04-01-050 2
D.21-06-035 13
D.21-07-014 1

California Public Utilities Commission Rules of Practice and Procedure

Rule 14.3 1

California Public Utilities Commision Proceedings

R.19-11-009 1
R.21-10-002 .... passim

SUMMARY OF RECOMMENDATIONS

SPECIFICATION OF ERROR

1. The proposed *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework* (PD) unjustifiably limits the ability for load serving entities (LSEs) to transact Resource Adequacy (RA) products in the 24-hour slice framework;
2. By not committing to revisit the Maximum Cumulative Capacity (MCC) bucket allocations to account for new resources coming online in the years prior to transitions to the new framework, the PD encroaches on LSEs' ability to utilize their RA portfolios by failing to reexamine the MCC bucket allocations for 2023 and 2024; and
3. The PD fails to allow the opportunity to advance a full unforced capacity methodology in the workstreams.

RECOMMENDED CHANGES

1. The PD should be revised to allow hourly transactions of RA, including both hourly resource trading and hourly RA obligation trading, under the 24-hour slice framework;
2. The PD should be modified to allocate Cost Allocation Mechanism resources to their applicable MCC bucket; and
3. The scope of workstreams two and three should be modified to consider a UCAP-light and a full UCAP methodology.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND REFORM TRACK FRAMEWORK

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework* (PD), issued May 20, 2022.

I. INTRODUCTION

The PD advances both long-term and near-term modifications to the RA program. The long-term modifications adopted within the Reform Track advance the 24-hour slice framework with the 2024 Resource Adequacy (RA) year as a test year and the 2025 RA year as the first compliance year under the new framework. The near-term modifications adopted within the Implementation Track include adoption of the 2023-2025 Local Capacity Requirements and the 2023 Flexible Capacity Requirements, modifications to the Planning Reserve Margin (PRM), and updates to the Effective Load Carrying Capability (ELCC) values for wind and solar resources.

<u>Reform Track</u>

Within the Reform Track, the PD errs by omitting hourly transactions through either hourly load obligation trading or hourly resource trading based on a host of misinformation or perceived barriers that can be easily overcome. The PD must be revised to allow load-serving entities (LSEs) to transact hourly in the 24-hour slice framework. Failure to do this will result in a framework that is unworkable and that fails to meet the important principles outlined by the Commission in Decision (D.) 21-07-014.[2]

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, Rulemaking (R.)19-11-009 (Jul. 15, 2021), at 26.

CalCCA supports the proposed timeline in which 2024 would be used as a test year prior to full implementation in 2025. This will allow parties to fully resolve outstanding elements and to work through any implementation details identified during the test year.

During this transition, the Commission should ensure LSEs can fully utilize their portfolios by not artificially limiting their megawatts (MW) allocations in the Maximum Cumulative Capacity (MCC) buckets by taking Cost Allocation Mechanism (CAM) resources off the top of LSEs' RA requirements. The Commission should, therefore, modify the PD to allocate CAM resources to their appropriate MCC buckets. Finally, CalCCA recommends the Commission modify the PD to consider unforced capacity (UCAP) within the RA reform workstreams to advance the transition to a full UCAP mechanism as opposed to only a "UCAP-light" mechanism.

<u>Implementation Track</u>

CalCCA strongly supports the PD's acknowledgment that additional Loss of Load Expectation (LOLE) modeling must be undertaken to inform the PRM. The PD strikes the right balance between the recognized reliability need for 2023 and this need for additional modeling by marginally increasing the PRM to 16 percent in 2023. The PD correctly directs Energy Division (ED) and parties to further vet the modeling inputs and assumptions in ED's LOLE study in the Integrated Resource Planning (IRP) proceeding to inform further updates to the PRM. Because the resource mix and load have changed significantly since the 15 percent PRM was originally adopted in D.04-01-050, a robust modeling process is critical to ensure the PRM results in an RA fleet that meets the 1-in-10 reliability target.

<u>Summary of Recommendations</u>

CalCCA's comments focus on modifications the Commission should make to the PD within the Reform Track to further advance the transactability and affordability of the RA program. In summary, CalCCA recommends the following modifications to the PD:

- The PD should be revised to allow hourly RA transactions under the 24-hour slice framework;
- The PD should be modified to allocate CAM resources to their applicable MCC bucket; and
- The scope of workstreams two and three should be modified to consider a UCAP-light and a full UCAP methodology.

Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs to give effect to these changes are included as Attachment A.

II. THE PD SHOULD BE REVISED TO ALLOW HOURLY RA TRANSACTIONS UNDER THE 24-HOUR SLICE FRAMEWORK

A. The 24-Hour Slice Framework Does Not Meet the Commission's First or Third Principle Without Hourly Transactions

The Commission's first principle of RA reform is: "To balance ensuring a reliable electric grid with minimizing costs to customers."[3] The PD fails to meet this critically important principle by failing to adopt hourly transactability with the 24-hour slice proposal. Prohibiting hourly transactions through hourly load obligation trading or hourly resource trading under a 24-hour slice framework creates serious negative impacts on the affordability of the RA program. The inability to transact hourly would significantly challenge LSEs' ability to meet their RA obligations by artificially constraining the RA market and unnecessarily increasing procurement and ratepayer costs. This is because LSEs would be required to show resources in all hours they are available even if the LSE does not need the resources in each hour to meet the LSE's compliance obligation. This unnecessarily limits LSEs' ability to conduct cost-effective procurement by capturing the diversity inherent in their load shapes and resource portfolios. In many cases, LSEs' portfolios may not perfectly shape to their hourly obligations, leading them to be short or long in certain hours but closely meeting their obligations in others. Hourly trading of either obligations or resources would allow LSEs to transact for the exact hours of need, without creating length where it is not needed to meet their compliance obligations. LSEs must be able either to shape their portfolios to match their obligations or shape their obligations to match their portfolios to (1) take advantage of diverse loads and resources amount LSEs, (2) minimize customer costs, and (3) mitigate against market power in an already constrained RA market. It is critical to build a reliability framework that also minimizes costs for CCAs and other LSEs to accelerate equitable and affordable clean energy for their customers.

The Commission's third principle to address through RA reform is: "To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability."[4] By adopting a 24-hour slice framework without hourly transactability, the PD effectively requires LSEs to transact a monthly RA product when compliance is assessed hourly. This creates a misalignment between the compliance intervals and the trading intervals that will impede on LSEs' ability to shape their RA portfolios to their obligations. By foregoing the

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[3] PD at 55.

[4] *Id.* at 55.

opportunity for LSEs to trade hourly, the Commission focuses too much on the "simplicity" component of its third principle at the expense of transactability. Under today's RA framework, LSEs can transact products that align with the compliance obligation. Today's RA program is monthly, and LSEs transact monthly products; the Commission does not require LSEs to procure quarterly or annual products to meet a monthly compliance obligation. The compliance intervals correctly drive the trading intervals. Absent such alignment, RA procurement would result in a suboptimal solution that fails to allow LSEs to closely align their procurement with their obligations. When moving to an hourly RA construct, the Commission should not mandate that LSEs procure for periods longer than the compliance obligation which is hourly.

To demonstrate the critical need for hourly trades to enhance the affordability and transactability of the 24-hour slice framework, assume a simplified system with two LSEs: LSE 1 and LSE 2. LSE 1 has a portfolio of firm, wind, solar, and storage resources and has an open position in hours ending (HE) 19, 20, and 21. LSE 2 has a portfolio of firm, solar, and wind resources, has no open positions, and is long in every hour. The total load plus PRM for LSE 1 and LSE 2 is met by the total resources from LSE 1 and LSE 2. However, without hourly transactability, LSE 1 would still need to fill its open position with new capacity. This is demonstrated in Figure 1, Figure 2, and Figure 3 below.

Figure 1

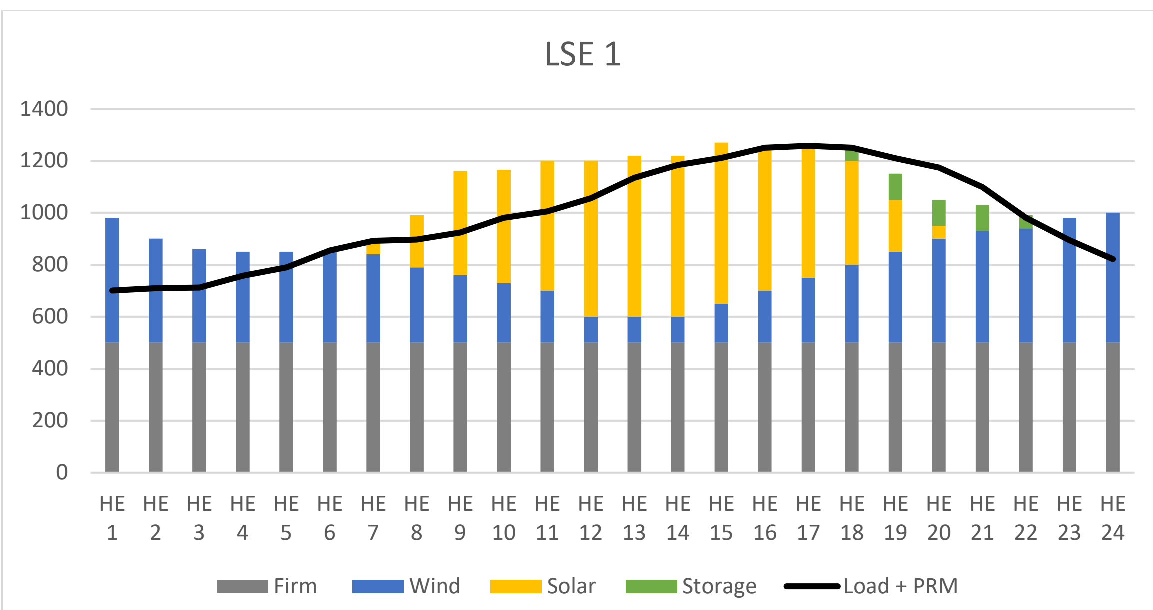


Figure 2

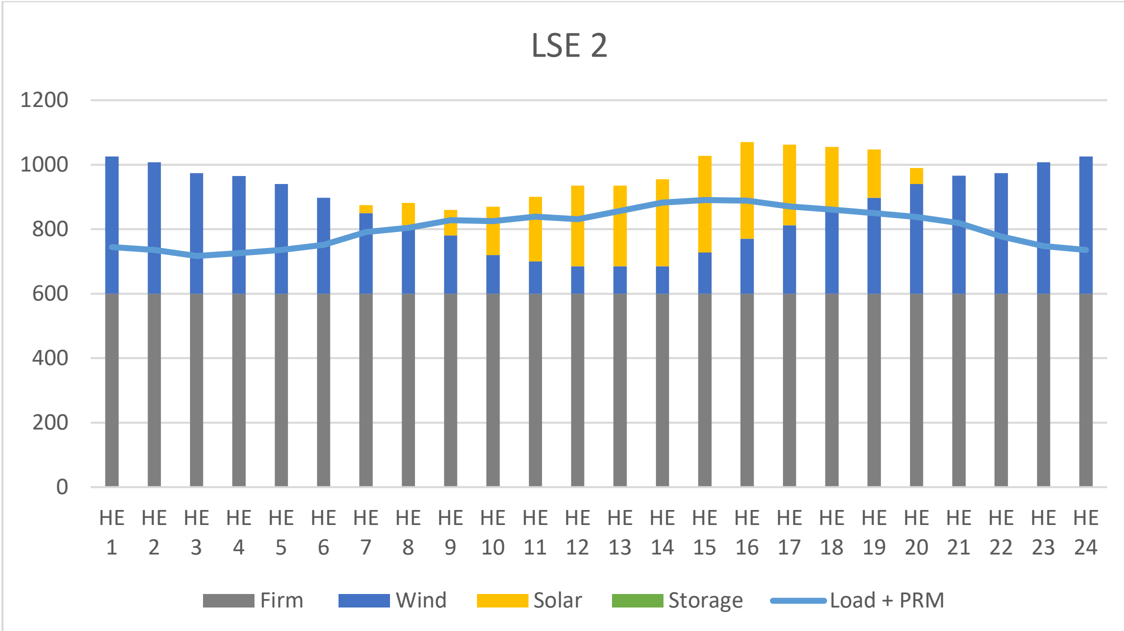
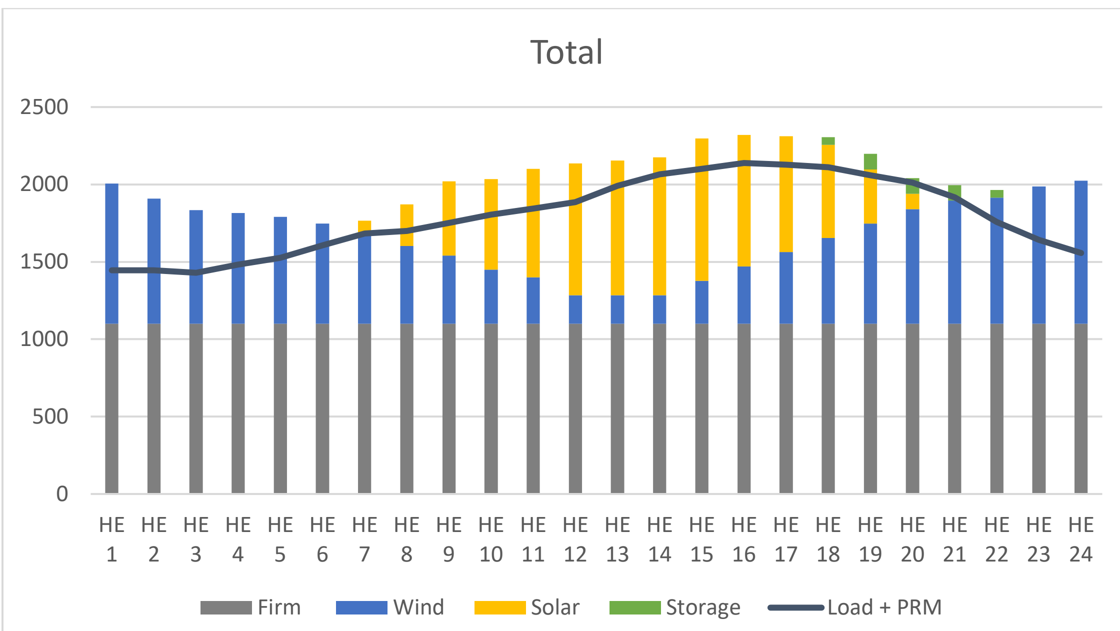


Figure 3



This illustrative example demonstrates that while LSE 1 and LSE 2 meet the total system RA requirements with the resources they have shown (Figure 3), LSE 1 would be found deficient (Figure 1). If LSE 1 had the ability to pay LSE 2 to take on its open position for its open hours, or if LSE 1 had the ability to sell its excess capacity in HE 19, 20, 21 to LSE 2, both LSEs would be found compliant with their obligations and the total system obligation would continue to be met.

As the PD stands, however, such transactions would not be permitted, and LSE 1 would need to procure an entirely new resource to satisfy its open positions, increasing customer costs unnecessarily. Alternatively, if LSE 1 could not procure a new resource, it would face penalties on the largest hour of deficiency for failing to meet its obligations despite total LSE procurement meeting the system needs as a whole. Such penalties would also unnecessarily increase customer costs because while the shown resources met the overall reliability need, the inability to transact properly under a 24-hour framework caused some LSEs to be unable to meet their own hourly need.

While PG&E suggests the ability for LSEs to choose the duration and hours they show storage could obviate the need for hourly transactions,[5] simply relying on LSEs to procure more storage when they have open positions will not result in the most cost-effective solution. Limiting an LSE's ability to transact hourly on the basis of using new storage would not only require procuring an entirely new battery resource and but also additional capacity to charge the battery, even if other LSEs have excess capacity during those hours. This duplicative procurement will increase costs. This should not be the only option available when another LSE or a resource may have excess capacity that it would be willing to trade. This would impede the affordability of the RA program by creating additional artificial RA market scarcity in an already constrained RA market.

While the 24-hour framework without hourly transactions does prevent LSE-leaning by requiring each LSE to procure to meet its own obligations, it does so at the expense of capturing diversity benefits between LSEs' load profile and resource portfolios. As long as LSEs are paying the cost of meeting their obligations by contracting with other LSEs, reliability costs are appropriately allocated to customers and leaning is avoided. Thus, preventing leaning and capturing diversity benefits do not need to be mutually exclusive. Both can be achieved by modifying the PD to allow hourly transactions. The PD must enhance the 24-hour slice framework to allow for hourly transactions in order to fully utilize LSEs' portfolios for RA compliance and maintain an affordable RA program.

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[5] PD at 93.

B. The PD Vastly Overstates the Barriers to Hourly Trading

1. Hourly Obligation Trading and Hourly Resource Trading are Fundamentally Different Mechanisms and Should Not be Conflated

Hourly obligation trading and hourly resource trading are fundamentally different mechanisms and should not be conflated. Hourly resource trading allows each LSE to contract with resources for the hours in which it needs capacity. This would allow generators or an LSE with excess resources to meet the needs of different LSEs by contracting with each. In contrast, hourly obligation trading does not involve generators (or their requirements) at all, but rather allows LSEs to contract for other LSE portfolios to use their resources to meet their obligations, much as IOUs do today through CAM.

The PD highlights a concern from SCE, who states that it is not clear why LSEs need both hourly load trading and hourly resource trading when hourly load trading alone would sufficiently address the need for hourly transactability.[6] While hourly load trading and hourly resource trading are distinct and separate methods for enhancing the transactability of the 24-hour framework, the Commission should adopt both to broaden the opportunities LSEs have to trade with other LSEs or contract with resources. The more opportunities and products LSEs have to meet their obligations, the more competition among providers there will be to sell such product, and hence, the more cost-effectively LSEs can meet their obligations.

2. Hourly Resource Trading is not Unbundling and Should be Coupled With the Existing 24X7 Must Offer Obligation

Hourly resource trading is <u>*not*</u> unbundling as the PD and party comments suggest.[7] System, local, and flexible RA attributes would continue to be bundled (*i.e.*, sold together) and the 24x7 must offer obligation would be maintained. In other words, any resource shown for any hour would continue to have a must offer obligation into the CAISO market for all hours subject to its use limitations, even if the resource was shown for only a sub-set of hours. This is not unlike a resource that is shown for capacity less than its minimum operating level (Pmin) today. While the resource would be shown for a value less than its Pmin, the resource's must offer obligation would be set to its Pmin so that the CAISO can operate the resource in its market. With hourly transactions and showings, the resource will offer all 24 hours and the CAISO's market will use the resource in hours the resource is economic and available, as it does today. The hourly RA

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6 PD at 93.

7 *Id.* at 94.

measure is an accounting exercise to validate that load plus a planning reserve margin is met assuming the CAISO operates the grid consistent with the hourly RA showing. The 24x7 must offer obligation quite simply ensures the CAISO market has access to the RA resources all hours of the day, even if LSEs only show a resource or if the resource only operators for a subset of those hours. This can and should be maintained under a 24-hour slice framework with hourly transactability.

Similarly, the hourly obligation trading mechanism also is not "unbundling" because it involves only trading of hourly obligations among LSEs and leaves the obligations and requirements of generators unaffected.

3. The PD Overstates the Complexity Required to Allow Hourly Trading

The PD states that parties oppose hourly resource trading because it would be administratively burdensome to track compliance, require additional showings, and hamper the framework's initial implementation.[8] This administrative complexity is overstated for both hourly resource trading and hourly load obligation trading. Systems can accurately track resources and LSEs' claims to them on an hourly basis. With the correct systems in place, trading load and resources by hour is no more complex than trading today. For example, trading load looks like a resource to the seller and additional load to the buyer. The additional complexity in the showings and validation process is primarily driven by transitioning to a 24-hour framework from the current gross peak framework, and only marginally driven by hourly trading.

Hourly Resource Trading

In opening comments to the working group report, CalCCA described how hourly ***resource*** trading can be easily tracked through a single showing for each LSE and resource.[9] In these comments, CalCCA outlined an example of a transaction between a resource and two LSEs:

- LSE 1 has procured a 24-hour 50 MW resource, Resource 1, to meet its obligations in HE 1 through HE 18
- LSE 2 needs 50 MW of capacity to meet its obligations in HE 19 through HE 21
- Resource 1 sells its 50 MW of capacity to LSE 1 from HE 1 through HE 18 and to LSE 2 from HE 19 through HE 21

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8 PD at 93.

9 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on The Future Of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 10-11.

In this example, the Commission would validate compliance by assuring the resource has not been shown for more than its full 50 MW in a single hour as demonstrated in Table 1. This would ensure that no resource is shown for the same capacity in multiple hours. The 24x7 must offer obligation should be maintained as described in Section 1 above such that resources shown in any hour would still have to offer its capacity 24x7 (and not just the hours they were shown in). This approach would ensure no capacity was double-counted and that the CAISO can continue to optimize the dispatch of all RA resources through its market as it does today.

Table 1

	HE 1	...	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
LSE 1 Showing (MW)	50	50	50	0	0	0	0	0	0
LSE 2 Showing (MW)	0	0	0	50	50	50	0	0	0
Resource 1 Supply Plan (MW)	50	50	50	50	50	50	50	50	50
Compliance Check									
Total LSE Showings = Resource 1 Supply Plan	✓	✓	✓	✓	✓	✓	✓	✓	✓

Hourly RA Obligation Trading

Additionally, the California Energy Storage Alliance (CESA), Peninsula Clean Energy (PCE), and San Jose Community Energy (SJCE) (together the Joint Parties) put forth a proposal for load obligation trading with detailed examples of how compliance would be tracked.[10] In summary, the Joint Parties propose "LSEs with short positions in some hours would be allowed to trade with others with long positions in those hours to allow resource sharing between the two LSEs with different loads and RA portfolios."[11] The Joint Parties' proposal provides an example and outlines detailed steps for RA showings.[12] Importantly, hourly RA obligation trading *does not* shift the responsibility of serving customer load, it would only shift the compliance obligation. LSEs that transact their RA obligations are still providing physical generation for their customers by contracting with other LSEs for RA capacity that will be available to the CAISO energy market, and then by bidding their load into that market to serve their customers. These are voluntary transactions and one LSE cannot force another LSE to take on their RA obligation. Rather, a transaction between LSEs would occur to compensate the load buying LSE for the capacity it is

10 *Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar.1 2022), at 196-205.
11 *Id.* at 202.
12 *Id.* at 204-205.

providing to meet that RA obligation. Effectively, the load selling LSE has procured an "RA resource" via another LSE rather than directly. Community choice aggregators (CCA) or other LSEs who engage in obligation trading would still be responsible for customer load service. Trading of obligations would have no bearing on the energy provided to the customer. This concept is no different than a CCA trading a resource to another CCA, a common practice under today's RA program.

To further illustrate how the Commission would check LSE and resource showings with an <u>*RA obligation*</u> trade for compliance, consider the following transaction:

- LSE 1 has procured a 24-hour 50 MW resource to meet its obligations in HE 1 through HE 18
- LSE 2 needs 50 MW of capacity to meet its obligations in HE 19 through HE 21
- LSE 2 pays LSE 1 to take its 50 MW open obligation

In this example, shown in Table 2 the LSE trading away its obligation would represent the trade as an MW decrease in its hourly obligation profile and the LSE receiving the obligation would show the trade as a MW increase to its RA portfolio. The MW decrease and MW increase on the LSEs' RA showings must sum to zero and the LSE receiving the obligation would accept all responsibilities for the obligation. When validating the showings, the Commission would ensure the total obligation before the trade equals the total obligation after the trade by requiring both LSEs to document the trade on their RA showing.

Table 2

Total Obligations									
	HE 1	...	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
LSE 1 Obligation	50	50	50	0	0	0	0	0	0
LSE 2 Obligation	0	0	0	50	50	50	0	0	0
Total Obligation Before Trade	50	50	50	50	50	50	0	0	0
LSE 1 Purchased/Sold Obligation	0	0	0	50	50	50	0	0	0
LSE 2 Purchased/Sold Obligation	0	0	0	-50	-50	-50	0	0	0
Total Obligation After Trade	50	50	50	50	50	50	0	0	0
Compliance Check									
Total Obligation Before Trade = Total Obligation After Trade	✓	✓	✓	✓	✓	✓	✓	✓	✓

The Commission must not impair LSEs' ability to fully transact to meet their obligations efficiently and cost-effectively on the basis of administrative complexity. Claims that hourly transactions would be too difficult to track in showings are overstated and clearly do not outweigh the significant affordability and transactability benefits hourly trading would provide LSEs in meeting their hourly obligations.

4. Existing Contracts Can and Should be Preserved in a Framework With Hourly Trading

The PD also states that not allowing for hourly transactions "preserves the value of existing contracts by alleviating the need for contract amendments and provides a simpler product to transact than an hourly product."[13] Maintaining the value of existing contracts is undeniably a critical component of RA reform and can be done simply while also adopting hourly trading. To accomplish this, the Commission should assume for RA showing and counting purposes that for any contract procured before the date of this decision, the resource sold all its hours to the buyer and, therefore, the LSE can show the resource in each hourly slice for the length of the contract unless the LSE chooses to sell a portion of those hours to another LSE under the hourly resource trading construct. This approach is consistent with the RA construct in place when the resource was sold; in which RA resources were procured to meet one hour (e.g., the gross peak hour plus a PRM) but were also required to be available in all other hours subject to use limitations through the must offer obligation such that the CAISO could operate the grid in all hours with the RA fleet.

Of course, since the hourly obligation proposal does not involve the RA generators, trading hourly obligations would not disturb those existing contracts in any way.

5. CAISO Processes can be Made Compatible With Hourly Trading

The PD expresses concern with elements raised by the CAISO over outage substitution, cost allocation and backstop procurement, and deliverability.[14] The CAISO raised these elements in its reply comments to the working group report but does not provide specific details as to why hourly transactions complicate these elements.[15] These elements are complicated by moving to a 24-hour framework in itself; hourly trading is not the primary source of the added complexity the CAISO mentions.

Regarding outage substitution, the CAISO would continue to assess outages and the need for substitution as they do today. When a resource is substituted for another resource on outage,

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13 PD at 94.

14 *Id.* at 93.

15 *Reply Comments on the Future of Resource Adequacy Working Group Report of the California Independent System Operator Corporation*, R.21-10-002 (Apr. 1, 2022), at 3-4.

the resource would continue to have a 24x7 must offer obligation subject to its use-limitations. Regarding cost allocation and backstop procurement, the CAISO systems do not currently recognize a 24-hour requirement. The CAISO systems simply check whether or not LSEs have met their single gross peak requirement. Whether there is hourly trading or not, the CAISO cannot determine cost allocation and backstop need on an hourly basis under its current tariff and processes. The PD instructs the Commission to work with the CAISO in determining changes necessary in the CAISO tariff to effectuate this 24-hour framework. These changes will need to be made regardless of hourly trading. Regarding deliverability, the CAISO currently evaluates deliverability at the time of peak and assigns deliverability during off-peak periods. It is not relevant whether a resource is shown for all off-peak hours or only a subset of off-peak hours. The system as designed will not be able to determine if the resources shown are deliverable in the periods that the CAISO does not currently study. A CAISO stakeholder process should consider changes needed to the deliverability methodology regardless of hourly trading.

Workstream 3 and the CAISO stakeholder process can and should address each of these concerns raised by CAISO to effectuate a 24-hour framework. Parties will largely need to address these issues whether or not the PD adopts hourly trading and, therefore, these issues should not be used as justification to foregoing hourly trading.

C. A Transactable RA Product Cannot be Achieved Through Swaps Alone

The PD states that under the 24-hour framework, "LSEs are not precluded from transacting or swapping with other LSEs to optimize their positions."[16] However, the PD fails to recognize that swaps are made more difficult by the 24-hour framework and may not always be a viable option for LSEs to meet their obligations. Constraining transactions among LSEs to swaps without hourly accounting will unnecessarily increase the likelihood LSEs would need to overprocure to meet their obligations at the expense of customer affordability.

Without hourly resource trading, it may be difficult to sell a resource as part of a swap. Currently, swaps deal with a single hour measure (gross peak load) and LSEs typically use them to swap other attributes like location (*e.g.,* swapping a system resource for a local resource) and ramping capability (*e.g.,* swapping a system or local resource for a flexible resource). Entering into a swap for 24-hour RA requirements means swapping parties will need to ensure the swap addresses their hours of need while not causing a deficiency in other hours since without hourly

[16] PD at 94.

transactions, the swapped resource will have to be sold for all hours of availability. This complicates the swap process making counterparties more difficult to find.

Additionally, swaps contain different risks to different parties. For example, LSE A has a resource with the full replacement obligation on the generator. LSE B has a resource with a full replacement obligation on the buyer. The difference in risk will need to be addressed in the swap transaction, making the swap more difficult. While the differential risk within a swap exists today, it is additionally complicated with the 24 hour nature of the new RA structure. Under the 24-hour slice framework, swaps will become more unlikely to resolve LSE needs. This is because each LSE will need to ensure they have enough capacity in each hour to meet their obligations, and that the swap does not create deficiencies in other hours after the swap.

III. THE PD SHOULD BE MODIFIED TO ALLOCATE CAM RESOURCES TO THEIR APPLICABLE MCC BUCKET

The PD adopts a transition approach to implementing the 24-hour slice framework in which 2024 would be a test year and 2025 would be the first year of compliance with the 24-hour slice framework. CalCCA supports this approach to allow time to resolve outstanding elements in the workstreams and work through implementation challenges identified in the test year. This means, however, that the MCC buckets will remain in place at least through 2024 as the workstreams examine the possibility of removing them. SCE raises in their opening comments to the working group report, a large amount of new storage resources will be coming online in response to the mid-term reliability D.21-06-035 in the IRP proceeding that will have reduced ability to meet RA needs because of MCC bucket restrictions.[17]

For CCAs, this problem is exacerbated by CAM. The Commission currently takes CAM resources "off the top" of LSEs' RA requirements, rather than allocating them to their applicable MCC bucket. As a significant amount of new clean resources come online and LSEs procure new clean resources to meet RPS requirements, resources that could otherwise be used for RA, may become crowded out of their applicable MCC bucket due to the way CAM allocations reduce the overall RA requirement rather than the MWs of MCC buckets they fit in. The Commission should modify the PD to allocate CAM resources to their applicable MCC buckets, rather than taking them off the top of LSEs' RA requirement. If the Commission declines to adopt this approach, the

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[17] *Southern California Edison Company's (U 338-E) Opening Comments on Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 13.

Commission should, at minimum, establish a working group on the proper MCC treatment of storage resources as SCE suggests and the proper MCC treatment of CAM resources.

IV. THE SCOPE OF WORKSTREAMS TWO AND THREE SHOULD BE MODIFIED TO CONSIDER A UCAP-LIGHT AND A FULL UCAP METHODOLOGY

In the working group discussions, parties discussed a UCAP and "UCAP-light" mechanism to determine the capacity value of dispatchable resources. UCAP would apply a forced outage rate to the Pmax of dispatchable resources to adjust their capacity values to account for forced outages. UCAP-light would apply a rate that only accounts for ambient derates due to temperature to the Pmax of dispatchable resources (and not other types of forced outages). The Commission states that it sees merit in the UCAP framework, as it better reflects resources' contribution to reliability and more effectively penalizes unavailable resources than the current Resource Adequacy Availability Incentive Mechanism (RAAIM) mechanism. However, given the "breadth of outstanding issues" to resolve prior to implementing the 24-hour framework the Commission defers consideration of the UCAP framework to a later phase of the proceeding.[18] Instead, the PD directs parties to attempt to establish UCAP-light mechanism in the workstreams.[19]

CalCCA supports the Commission's continued commitment to transitioning to a UCAP framework. UCAP provides incentives to perform maintenance that supports reliable operation of the resources by attributing unit-specific forced outage performance metrics into resources' capacity values. If the Commission instead includes forced outage percentages in the PRM, as is done today, an average forced outage rate must be spread uniformly across all resources who may have significantly different levels of reliability. This creates a cost shift where all other LSEs must procure marginally more resources to account for the outage rates of high outage resources in other LSE's portfolios. Unit-specific outage rates also allow LSEs to assess the reliability of resources when making contracting decisions and the CAISO to eliminate its RAAIM tool.

The PD is correct that implementation details must be worked out for both the UCAP-light and UCAP mechanisms. Many of these details overlap between a UCAP and a UCAP-lite. The Commission should therefore expand the scope of workstreams two and three to advance the full UCAP methodology. UCAP-light does not fully capture the benefits of a UCAP mechanism, as UCAP-light only considers a portion of forced outages. If the workstreams cannot advance UCAP

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18 PD at 96.

19 *Id.* at 82.

far enough to implement with the initial RA reform implementation in 2025, a UCAP-light could instead be implemented as an interim measure while the full UCAP mechanism is finalized. Workstreams two and three are the right places to have this discussion, given the impact of UCAP on resource counting, the PRM, and CAISO processes.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the PD as provided in Attachment A.

Respectfully submitted,

Evelyn Kahl

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

June 9, 2022

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND REFORM TRACK FRAMEWORK

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

FINDINGS OF FACT

11. Given the complexities of implementing a new statewide RA framework, it is prudent to establish a 2024 test year to allow additional time for implementation and potential adjustments, prior to full implementation in the 2025 RA year. <u>Prior to full implementation, CAM allocations should be allocated to LSEs by the applicable MCC bucket to ensure full utilization of new clean RA resources.</u>

CONCLUSIONS OF LAW

None.

ORDERING PARAGRAPHS

27. The following workstreams are adopted for further development of the 24-hour framework:

(1) Workstream 1. Develop 24-hour framework compliance tools:

a. Resource Adequacy (RA) Resource Master Database to be coordinated with California Independent System Operator (CAISO).

b. Load-Serving Entity (LSE) Showing Tool (template to be used by the LSE to make its filing to the Commission)<u>, including the ability to transact both resources and obligations hourly,</u> and Commission Verification Tool (tool to be used by Energy Division to verify compliance), <u>including the ability to verify hourly transactions</u>.

c. LSE Requirement Database to be coordinated with the California Energy Commission (CEC). This will utilize outputs generated by the CEC's load forecast proposal, including a dry run filing that may inform any necessary changes.

d. Cost Allocation Mechanism (CAM) process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.

(2) Workstream 2. Determine Planning Reserve Margin (PRM) and Counting Rules:

a. Appropriate exceedance level and hourly profiles for wind and solar at technology and/or location level.

b. Counting rules for hybrid, co-located, and long-duration energy storage resources, as well as development of a Unforced Capacity Evaluation-light (ambient derate) mechanism <u>or full Unforced Capacity Evaluation mechanism (ambient derate and other forced outages)</u> to be applied to dispatchable resources.

c. Elimination of the maximum cumulative capacity buckets.

d. Test year details.

e. Appropriate PRM with single PRM initially for all months and hours informed by a loss of load study, including National Resources Defense Council's calibration tool.

(3) Workstream 3. CAISO and Commission Validation and Compliance as follows:

a. Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.

b. Identify and resolve administrative changes to the RA program at both CAISO and the Commission (e.g., must-offer reporting, outage substitution, <u>implementation of UCAP/removal of RAAIM</u>).

c. Elimination of the flexible RA requirements.

New Order:

<u>CAM resources shall be allocated to LSEs in the applicable MCC bucket.</u>

<u>LSEs shall be permitted to transact load obligations or resources on an hourly basis under the 24-hour framework.</u>

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION ESTABLISHING RULES FOR PORTFOLIO CONTENT CATEGORY CLASSIFICATION FOR VOLUNTARY ALLOCATIONS OF RENEWABLES PORTFOLIO STANDARD RESOURCES

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June 9, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S FINDING THAT RECS ALLOCATED THROUGH THE VOLUNTARY ALLOCATION SHALL RETAIN THEIR PCC STATUS 2

III. THE COMMISSION SHOULD CLARIFY THAT LSES ARE NOT REQUIRED TO SEEK APPROVAL FOR VOLUNTARY ALLOCATIONS 3

IV. THE COMMISSION SHOULD CLARIFY THE RPS REPORTING REQUIREMENTS FOR LSES NOT PARTICIPATING IN VAMO 3

V. CONCLUSION 4

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.11-12-052 2
D.21-05-030 2

California Public Utilities Commision Rulemakings

R.17-06-026 2
R.18-07-003 .... 1, 2

California Public Utilities Commission Rules of Practice and Procedure

Rule 14.3 1

SUMMARY OF RECOMMENDATIONS

- ✓ The California Public Utilities Commission (Commission) should adopt the Proposed Decision's findings that renewable energy credits allocated from investor-owned utilities to load serving entities (LSEs) through the Voluntary Allocation process shall retain their Portfolio Content Category status;
- ✓ The Commission should clarify that LSEs need not request approval of Voluntary Allocations as stated in the Administrative Law Judge's May 20, 2022 Ruling on the Renewable Portfolio Standard Procedural Schedule; and
- ✓ The Commission should clarify the reporting requirements for LSEs electing not to participate in the Voluntary Allocation.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ESTABLISHING RULES FOR PORTFOLIO CONTENT CATEGORY CLASSIFICATION FOR VOLUNTARY ALLOCATIONS OF RENEWABLES PORTFOLIO STANDARD RESOURCES

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Establishing Rules for Portfolio Content Category Classification for Voluntary Allocations of Renewables Portfolio Standard Resources* (Proposed Decision or PD), mailed on May 20 2022.

I. INTRODUCTION

CalCCA fully supports the Proposed Decision and recommends its adoption, with the clarifications set forth below. Expeditious approval of the Proposed Decision at the Commission's voting meeting on June 23, 2022 (or as soon thereafter as possible) will allow the Renewables Portfolio Standard (RPS) Voluntary Allocation and Market Offer process (VAMO)

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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.

to proceed according to the schedule set forth in the May 20, 2022 ALJ Ruling on the Renewable Portfolio Standard procedural schedule.[2]

The Commission should adopt the Proposed Decision's findings that renewable energy credits (RECs) allocated from investor-owned utilities (IOUs) to load serving entities (LSEs) through the Voluntary Allocation (VA) process shall retain their Portfolio Content Category (PCC) status. In addition, the Commission should adopt the following clarifications as set forth below and in Appendix A:

- Clarify that LSEs need not request approval of VAs as stated in the ALJ Ruling; and
- Clarify the reporting requirements for LSEs electing not to participate in the VA.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S FINDING THAT RECS ALLOCATED THROUGH THE VOLUNTARY ALLOCATION SHALL RETAIN THEIR PCC STATUS

The Proposed Decision correctly finds that a REC's PCC status shall be retained in the VAs.[3] Allowing resources allocated to LSEs to retain the RPS benefits upon allocation ensures that Power Charge Indifference Adjustment (PCIA)-eligible customers for whom the RECs were initially procured continue to receive the benefits intended in the Phase 2 PCIA Decision.[4] In addition, CalCCA supports the Proposed Decision's finding that downstream transfers of the RPS attributes of a VA product should be considered a resale for the purpose of determining PCC classification pursuant to D.11-12-052.[5] Finally, the Commission should revise the Conclusions of Law as set forth in Appendix A to correct the typo referring to D.11-12-052.

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2 *Administrative Law Judge's Ruling Modifying the Renewables Portfolio Standard Program's Procedural Schedule to Accommodate Filing of Voluntary Allocation and Market Offer Information Adopted in Decision 21-05-030,* R.18-07-003 (May 20, 2022) (ALJ Ruling).

3 PD, Ordering Paragraph (OP) 2-3.

4 D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 24, 2021) (Phase 2 Decision); *see also* PD at 22, OP 2.

5 PD at 21, OP 9.

III. THE COMMISSION SHOULD CLARIFY THAT LSES ARE NOT REQUIRED TO SEEK APPROVAL FOR VOLUNTARY ALLOCATIONS

While LSEs must seek approval of their RPS Plans, the Commission should clarify that LSEs are not required to seek Commission *approval* of their VA contracts. The Proposed Decision clarifies that IOUs are not required to seek upfront approval of executed (unmodified) pro forma VA contracts through the Advice Letter process.[6] CalCCA supports the Proposed Decision's finding that only contracts deviating from the pro forma will be subject to further review through a Tier 1 Advice Letter.[7] However, the ALJ Ruling requires LSEs to submit Motions to Update Draft 2022 RPS Plans on August 15, 2022 "including *request[] approval of voluntary allocations* and up-to-date [VA] information."[8] The Commission should clarify that while LSEs should provide in their August 15, 2022 Motions to Update any information obtained regarding their VAs after the filing of the original draft RPS Plans on July 1, 2022, LSEs *need not request approval* of executed VA contracts.

IV. THE COMMISSION SHOULD CLARIFY THE RPS REPORTING REQUIREMENTS FOR LSES NOT PARTICIPATING IN VAMO

The Proposed Decision should clarify requirements for RPS reporting for LSEs that choose *not* to participate in the VAMO. The PD states:

> [f]or RPS compliance reporting for VAMO transactions, Energy Division staff will provide reporting guidance in next year's updated RPS compliance reporting template. Energy Division and LSEs should work together to refine reporting requirements for voluntary allocations, resales, market offers, and unsold volumes.[9]

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6 *Id.* at 17.
7 *Id.* at 22, OP 5.
8 ALJ Ruling at 6 (Table, Item 22) (emphasis added).
9 PD at 16.

In addition, Energy Division staff provided information regarding the necessary VAMO content of the 2022 RPS Plans at its May 31, 2022 Webinar.[10] Energy Division requests that LSEs explain in their July 1, 2022 filing "why they plan[] to participate [in VAMO] or not."[11]

CalCCA requests that the Commission clarify this requirement. LSEs electing *not* to participate in the VA or the MO should merely state in their RPS Plans that they chose not to participate. LSEs may provide an optional, general description of the basis for that decision.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these comments supporting the Proposed Decision, and requesting clarifications to the findings as provided in Attachment A.

Respectfully submitted,

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

June 9, 2022

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10 *Renewables Portfolio Standard (RPS) Webinar on 2022 RPS Procurement Plan Templates and Filing Requirements* (May 31, 2022), https://files.cpuc.ca.gov/RPS_PPAs/Procurement%20Plans/RPS%20Webinar%20on%202022%20RPS%20Procurement%20Plans-20220531%202203-1.mp4

11 *Id.,* Slide 9.

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION ESTABLISHING RULES FOR PORTFOLIO CONTENT CATEGORY CLASSIFICATION FOR VOLUNTARY ALLOCATIONS OF RENEWABLES PORTFOLIO STANDARD RESOURCES

PROPOSED CHANGES TO CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

CONCLUSIONS OF LAW

9. Any downstream transfers of the RPS attributes conveyed through a Voluntary Allocation should be considered a resale to determine PCC classification pursuant to ~~D.12-11-052~~<u>D.11-12-052</u>.

ORDERING PARAGRAPHS

<u>7. Load-serving entities need not seek approval of executed pro forma Voluntary Allocation contracts in their Renewables Portfolio Standard Plans, but should rather describe the Voluntary Allocation contract as required by Energy Division guidance and templates.</u>

<u>8. A load-serving entity choosing not to participate in the Voluntary Allocation or the Market Offer shall state in its Renewable Portfolio Standard Plan that it chose not to participate and provide a general description as to the basis for that decision.</u>

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
ENERGY INDEX MPB CALCULATION PROPOSAL

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June 13, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY 1

II. THE MEAGER, AND POTENTIALLY NON-EXISTENT, BENEFITS OF A LESS TRANSPARENT MODEL MAY NOT OUTWEIGH THE COSTS 3

A. Switching to Generation-Based Weighting May Not Materially Improve the Accuracy of PCIA Rates 3

B. Any Methodology Should Balance Accuracy With Transparency and Verifiability 8

III. CALCCA EI PROPOSAL AND RESPONSES TO ALJ RULING QUESTIONS 9

1. What is the problem with the current Energy Index calculation methodology and/or data source? 10

2. Would it be sufficient to continue using Platts data to calculate on-peak and off-peak indices, with the Commission simply updating the percentage weights that each IOU applies to the on- and off-peak indices? Why or why not? 11

3. Platts data are proprietary. Are there non-proprietary data sources that could result in an Energy Index of equal or better quality than the current Energy Index? If so, what are those data sources? 11

4. If only proprietary data sources would result in an Energy Index of equal or better quality than the current Energy Index, what are those data sources? 12

5. Is there a cost to obtain any of the data you identified in your responses above? If so, what is the cost? 12

6. Based on the data sources you identified in your responses above, discuss the benefits and drawbacks of the following entities calculating the Energy Index, in terms of cost, efficiency, and transparency: 12

7. How will the Energy Index and any related weights be calculated? Describe the data sources, the data scope (e.g., which months or years of data will be used, as applicable), the timing of calculations prior to the October Update, and the calculation methodology for both the Energy Index itself and any weights. 13

8. Who will calculate the Energy Index and any related weights? For example, will Energy Division staff, the IOUs, or a third-party consultant collect necessary data and perform the calculations? 16

TABLE OF CONTENTS (cont.)

9. What is the cost of obtaining necessary data and performing the calculations? How will this cost be recovered? 16

10. How would this proposal improve upon the current situation? In answering this question, address the following sub-questions: 16

IV. CONCLUSION...18

TABLE OF AUTHORITIES

Page

California Public Utilities Commision Proceedings

R.17-06-026 .... passim

SUMMARY OF RECOMMENDATIONS

- Modifications to the Energy Index (EI) market-price benchmark (MPB) calculation method must not diminish current levels of transparency. Non-investor-owned utility (IOU) load serving entities must be able to independently analyze and plan for changes in power charge indifference adjustment (PCIA) rates.

- Modifying the EI MPB calculation method to rely on PCIA-eligible generation rather than bundled customer load will align the EI inputs and the MPB application within the PCIA.

- The IOUs' reliance on production cost modeling to forecast PCIA-eligible generation as an input to the EI will reduce transparency into the EI formula.

- California Community Choice Association (CalCCA) proposes the use of a rolling five-year average historical generation output from PCIA-eligible resources to develop monthly on- and off-peak generation weightings.

- Monthly on- and off-peak generation weightings should be applied to Platts monthly on- and off-peak forward market prices to derive the forecasted EI MPB.

- The process and timing for calculating and disseminating the forecasted EI should remain the same after incorporating the changes to volume and price inputs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
ENERGY INDEX MPB CALCULATION PROPOSAL

The California Community Choice Association[1] (CalCCA) submits this proposal in response to the *Administrative Law Judge's Ruling Regarding Market Price Benchmarks* (Ruling), issued April 18, 2022 in the above-captioned proceeding, and Judge Wang's *Procedural Email re Joint IOUs' MPB Ruling Energy Index Comments Extension Request*, issued May 16, 2022 in the above-captioned proceeding. The Ruling requests proposals on how to calculate certain Market Price Benchmarks (MPBs) used to set each investor-owned utility's (IOU's) Power Charge Indifference Adjustment (PCIA). Specifically, this proposal responds to the Ruling requesting proposals for calculating the Energy Index (EI) MPB.

I. INTRODUCTION AND SUMMARY

The current EI is a weighted-average forward market price, calculated by applying the Platts annual on- and off-peak market price forecast to the IOU's bundled customer load profile.

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

As referenced in the Ruling, the IOUs filed comments earlier in this proceeding advocating changes to the EI calculation, arguing that "the PCIA-eligible generation portfolio supply resources often garner California Independent System Operator (CAISO) market revenues that are far less than the Platt's on- and off-peak predicted 'average'" that is currently used to set the EI component of forecast PCIA rates.[2] The IOUs imply that a bundled customer load profile is more heavily weighted to the on-peak period than the generation output of PCIA-eligible resources, creating a mismatch between the two main inputs to the EI: market prices and volume.

After evaluating generation data provided by the IOUs in response to data requests, CalCCA developed a generation-weighted EI MPB calculation proposal to align the price and volume inputs. Analysis supporting CalCCA's proposal demonstrates that, while bundled customer load may have a different time profile than the generation output of the IOUs' PCIA-eligible resource portfolio, changing the volume weighting for the EI can increase or decrease the EI MPB.

CalCCA's proposal balances objectives of increasing forecast accuracy and maintaining transparency for stakeholders and customers. Instead of bundled customer load, actual generation output from PCIA-eligible resources is used to calculate monthly on- and off-peak ratios, and these ratios are multiplied by monthly on- and off-peak forward market prices to derive a generation-weighted EI MPB. CalCCA's proposal is consistent with PG&E's earlier comments in the OIR proceeding advocating for a monthly volume-weighted approach. PG&E stated:

> Beneficial changes can be accomplished by using the PCIA supply generation presented in the ERRA Forecast cases, instead of historical bundled load demand, and the monthly Platt's on peak/off peak energy prices. When developing the energy benchmark, utilization of each IOU's respective PCIA supply portfolios when determining a monthly on peak/off

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2 *SCE Opening Comments on Ruling re Market Price Benchmark Issue Date*, R.17-06-026 (Sept. 13, 2021), at 5-6 (internal citations omitted).

> peak weightings, rather than customer load, will improve the precision of the forecasted brown power index.[3]

The difference between PG&E's suggestion and CalCCA's proposal is the reliance on *historical generation output* to avoid relying on the IOUs' production cost modeling as an input to the EI.

If the California Public Utilities Commission (Commission) finds that reform to the EI is warranted, any changes to the formula must balance accuracy and transparency. Under CalCCA's proposal, the process and timing for publishing the EI will be largely the same as it is today. And, importantly, non-IOU load serving entities (LSEs) will continue to have visibility into the market prices and monthly weightings, which facilitates independent analysis and planning to manage rates for customers subject to the PCIA. If reform requires reduced transparency into the EI formula, however, the current method should remain in place.

II. THE MEAGER, AND POTENTIALLY NON-EXISTENT, BENEFITS OF A LESS TRANSPARENT MODEL MAY NOT OUTWEIGH THE COSTS

A. Switching to Generation-Based Weighting May Not Materially Improve the Accuracy of PCIA Rates

As referenced in the Ruling, PG&E and SCE filed comments earlier in this proceeding advocating for changes to the EI calculation.[4] The current EI is a weighted average forward market price, calculated by applying Platts annual on- and off-peak forward market prices for NP15 and SP15 to the percentage of bundled customer load in the on- and off-peak periods. PG&E and SCE each argue that change is warranted due to departing load and varying compositions of their PCIA-eligible generation resource portfolio.

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3 PCIA Phase 2 PG&E ERRA Ruling Comments (Sept. 13, 2021), at 5.

4 As noted in the Ruling, San Diego Gas & Electric Company (SDG&E) agreed with SCE's and PG&E's arguments. Ruling at 1-3; *San Diego Gas & Electric Company Reply Comments on Ruling Regarding Market Price Benchmark Issue Date*, R.17-06-026 (Sept. 22, 2021), at 5-6 ("SDG&E agrees with both PG&E and SCE that changing the load weighting methodology for the Energy Index MPB to be based on each IOU's generation profile shapes would increase the accuracy of the PCIA MPBs and forecasted PCIA rates").

PG&E stated:

> At the time the Commission developed this methodology, parties reasonably assumed that the bundled service customer load profile (i.e., demand) was not expected to differ substantially from the IOUs' generation output portfolio (i.e., supply) relevant to the PCIA calculation. However, as all parties to this proceeding are aware, since 2011, PG&E has experienced significant load departure due to, among other things, Community Choice Aggregation ("CCA") and Direct Access ("DA") growth…Further, changes to California's energy supply portfolio, including the growth intermittent renewable energy resources within PG&E's energy supply portfolio causes a misalignment in energy benchmark…As a result, use of PG&E's bundled customer load-weighting to develop the energy benchmark is outdated given the significant changes to PG&E's portfolio and load departure and supply portfolios.[5]

SCE made similar comments, arguing, "[t]hose PCIA-eligible generation portfolio supply resources often garner CAISO market revenues that are far less than the Platt's on- and off-peak predicted 'average' that is reflected in the index, and which is currently used to set the [EI] MPB component of forecast PCIA rates."[6] In other words, the IOUs argue that a bundled customer load profile is more heavily weighted to the on-peak period than the generation profile of PCIA-eligible resources. In that case, if generation output were used to weight the EI, a lower weight would be assigned to on-peak market prices, thereby reducing the market value of the generation resource and increasing PCIA rates.

The generation output of the IOUs' PCIA-eligible resource portfolio may have a different time profile than bundled customer load. However, analysis of each IOU's historical generation data does not support the blanket assertion that the current EI is inadequate. In response to discovery, each IOU provided CalCCA's Reviewing Representative (NewGen Strategies and

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[5] *PCIA Phase 2 PG&E ERRA Ruling Comments*, R.17-06-026 (Sept. 13, 2021), at 4-5 (internal citations omitted).

[6] *SCE Opening Comments on Ruling re Market Price Benchmark Issue Date*, R.17-06-026 (Sept. 13, 2021), at 5-6.

Solutions, or NewGen) aggregated hourly generation profiles for their PCIA-eligible resource portfolio spanning the years 2017 – 2021. These data lead to two conclusions: (1) the IOUs' PCIA-eligible generation output is more concentrated to on-peak periods than bundled customer load, largely due to the expansive definition of "on-peak" used in energy markets in the western United States; and (2) a load-weighted EI is materially comparable to a generation-weighted EI calculated using average historical PCIA-eligible resource output.

Summarizing hourly generation into on- and off-peak periods allows a comparison to the bundled load shape used in the IOUs' PCIA calculations. The table below compares annual on- and off-peak generation output to the load profile used in each IOU's latest Commission approved PCIA:

Table 1: On- and Off-Peak Ratios – Generation Output vs. Load

		PG&E		SCE		SDG&E	
		On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
Generation	2017	62%	38%	62%	38%	68%	32%
	2018	63%	37%	64%	36%	70%	30%
	2019	62%	38%	65%	35%	69%	31%
	2020	64%	36%	68%	32%	69%	31%
	2021	63%	37%	68%	32%	69%	31%
	Load	59%	41%	62%	38%	61%	39%

On an annual basis, the percentage of on-peak generation output is greater than on-peak bundled load. If annual generation output were used to weight the on- and off-peak market price in the EI, market value would be higher (and PCIA rates would be lower) compared to the *status quo*.

Additional variation in the on- and off-peak percentages for generation exists on a monthly basis, as shown below for 2021, but the percentage of on-peak generation is generally still greater than the annual bundled load profile currently used for the PCIA.

Table 2: Monthly On- and Off-Peak Generation Ratios – Calendar Year 2021

	PG&E		SCE		SDG&E	
	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
January	60%	40%	64%	36%	70%	30%
February	64%	36%	69%	31%	72%	28%
March	67%	33%	70%	30%	71%	29%
April	67%	33%	72%	28%	70%	30%
May	62%	38%	65%	35%	67%	33%
June	66%	34%	70%	30%	69%	31%
July	63%	37%	69%	31%	66%	34%
August	63%	37%	69%	31%	69%	31%
September	63%	37%	67%	33%	69%	31%
October	64%	36%	67%	33%	69%	31%
November	62%	38%	67%	33%	67%	33%
December	61%	39%	63%	37%	72%	28%

It makes sense that generation output would be concentrated to on-peak periods given the wholesale market definition of 'on-peak' and 'off-peak' and the composition of the IOUs' respective PCIA resource portfolios. Energy markets in the western United States define on-peak hours as the *16 hours* from 6:00 am to 10:00 pm, Monday through Saturday, excluding NERC holidays. Furthermore, the IOUs' PCIA eligible resource portfolios have significant proportions of solar and natural gas generation which tend to produce the bulk of their output during the 16-hour on-peak market period.

The EI is a volume-weighted average market price derived by summing the result of two calculations: (1) the percent of on-peak volume multiplied by a forecasted on-peak price; and (2) the percent of off-peak volumes multiplied by a forecasted off-peak market price. NewGen performed this same calculation with historical generation and CAISO market price data on various time scales to compare the results using each IOU's generation and bundled load profiles. First, the annual average on- and off-peak day ahead market prices were multiplied by the annual load profile[7] to determine the historical load-weighted average market price – replicating the EI methodology but on a historical basis. Next, the annual average on- and off-peak market prices were multiplied by the annual generation profile for the same period to derive annual generation-weighted market prices specific to each IOU. Finally, actual monthly on- and off-peak market prices were multiplied by monthly on- and off-peak generation profiles to determine a monthly generation-weighted market price.

The table below compares the results of all three methods using data from 2019 – 2021:

Table 3: Load Versus Generation Weighted Historical Market Prices

	PG&E			SCE			SDG&E		
	2019	2020	2021	2019	2020	2021	2019	2020	2021
CAISO Annual On Peak Day Ahead Price	38.19	35.13	56.37	37.91	38.25	53.41	37.91	38.25	53.41
CAISO Annual Off Peak Day Ahead Price	32.46	28.52	47.24	32.44	28.52	45.51	32.44	28.52	45.51
On Peak Load	59.2%	58.6%	58.6%	61.9%	61.9%	61.9%	60.6%	60.6%	60.6%
Off Peak Load	40.8%	41.4%	41.4%	38.1%	38.1%	38.1%	39.4%	39.4%	39.4%
Annual Load Weighted Market Price	35.85	32.39	52.59	35.83	34.55	50.40	35.76	34.42	50.30
On Peak Generation	62.4%	63.5%	63.3%	64.7%	67.8%	67.9%	69.4%	68.7%	69.0%
Off Peak Generation	37.6%	36.5%	36.7%	35.3%	32.2%	32.1%	30.6%	31.3%	31.0%
Annual Generation Weighted Market Price	36.03	32.72	53.02	35.98	35.12	50.87	36.24	35.21	50.96
Difference vs. Load Weighted	0.5%	1.0%	0.8%	0.4%	1.6%	0.9%	1.3%	2.3%	1.3%
Monthly Generation Weighted Market Price	35.62	32.76	54.25	34.72	35.29	50.55	36.29	36.18	51.47
Difference vs. Load Weighted	-0.6%	1.1%	3.2%	-3.1%	2.1%	0.3%	1.5%	5.1%	2.3%

The last row, labeled “Difference vs. Load Weighted,” in Table 3 demonstrates how the generation-weighted market value of PCIA generation can be lower or higher than the load-weighted average market price. If generation-weighting (the IOUs’ proposed methodology) was materially different than load-weighting (the current methodology), one would expect the values in the last row to be consistently negative or consistently positive; however, that is not the case.

Load and generation characteristics from a particular year, or changes to an IOU’s profile, may alter the results. Variations in PCIA-eligible resource mix will also affect the results

[7] IOU bundled load profiles were taken from each utility’s ERRA Forecast applications for 2022 and prior but with a two-year lag. For example, the 2019 load profiles are those used in the 2021 ERRA Forecast.

— portfolios with a higher proportion of generation that is not well correlated to either load or the highest market prices will exhibit larger variations in EI value compared to load. However, that variability underscores that it is not clear that using annual or monthly generation output to determine a weighted average market price is consistently or materially different from the current EI method that relies on a bundled load profile.

B. Any Methodology Should Balance Accuracy With Transparency and Verifiability

CalCCA opposes relying on the IOUs' internal forecasting to determine the EI. SCE previously requested each IOU "be authorized to forecast the market value of the energy from its PCIA portfolio using the same methodology/model used to set the IOU's bundled service and overall PCIA forecast rates, which for SCE is a production cost model."[8] Among other things, SCE argued the benefit of using its production cost model will include eliminating the need for the Platts-based energy index and increasing consistency between forecasts of bundled service customers rates and departing load customer rates (PCIA).[9]

However, the approach lacks transparency in three dimensions: volume, price, and timing. Transparency in calculating the PCIA rates charged to customers is critical for CCAs and other entities serving departed load customers. One of the benefits of the current EI calculation is that each party can obtain the inputs to the MPB without relying on the IOUs or dealing with IOU market sensitive data. If, instead, the current calculation is replaced by each IOU's forecast of wholesale market revenue based on its own production cost modeling, this benefit will be lost. Stakeholders will not have access to the data inputs to the EI MPB calculation, removing any ability to plan for changes to the PCIA.

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8 *SCE Opening Comments on Ruling re Market Price Benchmark Issue Date*, R.17-06-026 (Sept. 13, 2021), at 9.

9 *Ibid.*

In addition, because each IOU may prepare its forecast using different inputs and different production cost models, even a common framework will presumably result in each IOU applying different price curves and using different timelines for running its models. Instead of a uniform method for determining the relevant EI, each IOU would in effect create its own methodology. As a result, all reviewers, including Commission Staff, will need more time to review the process undertaken and the resultant PCIA calculations.

SCE suggests the true-up of PCIA rates and the ability of market participants to hire reviewing representatives solves these problems.[10] However, the process to retain such reviewing representatives and deal with persistent objections and delays in receiving responses to those requests during the expedited discovery process is far from the streamlined process SCE holds it out to be. There is little about the ERRA forecast proceeding that is transparent, especially for the general public. Confidential data accessed within an ERRA proceeding cannot be used outside that proceeding or for any other purpose, such as modeling anticipated changes in PCIA rates. This opacity problem is especially acute with regard to analyzing production-cost modeling, which is a data and resource-intensive process that requires specialized analysts, increasing costs for both the Commission and parties, especially those like the CCA parties representing ratepayer interests. The meager, and potentially non-existent, benefits of a less transparent model do not outweigh these costs.

III. CALCCA EI PROPOSAL AND RESPONSES TO ALJ RULING QUESTIONS

Efforts to increase the accuracy of the PCIA forecast and avoid unnecessary after-the-fact true-ups will reduce rate volatility for all customers. While the analyses conducted to date do not show clear benefits from switching to generation-weighting from load-weighting, there is an

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10 *SCE Opening Comments on Ruling re Market Price Benchmark Issue Date*, R.17-06-026 (Sept.13, 2021), at 9.

inherent consistency in using generation output to weight the market price index applied to generation resources when determining the IOUs' indifference Amount and PCIA rates.

If the Commission determines this inherent consistency warrants a change to the current methodology, forecast accuracy must be balanced with transparency so that CCAs can plan for and prudently manage rate impacts to their customers. CalCCA proposes to ensure this balance by modifying the EI method to rely on a rolling five-year historical average of monthly PCIA-eligible generation to calculate on- and off-peak weights that can be applied to monthly Platts forward market prices. The current process and timeline for calculating the forecast EI would remain largely intact, except that the IOUs would be required to provide generation data, rather than the bundled load profile, in their annual ERRA Forecast applications. This incremental change to the EI calculation builds on the utilities' proposals to tie generation-based weighting to generation values without requiring the Commission, stakeholders, and, most importantly, customers to rely on inscrutable production cost modeling. CalCCA's proposal is detailed below in its responses to the questions presented in the Ruling:

1. What is the problem with the current Energy Index calculation methodology and/or data source?

The problem, based on CalCCA's analysis, is academic. The current EI is a weighted average forward market price, calculated by applying a bundled customer load profile to the Platts annual on- and off-peak market price forecast for NP15 and SP15. Because the EI is used to calculate the value of PCIA-eligible generation resources, PG&E and SCE have previously argued that the EI should reflect the generation resource output rather than a bundled load profile. In concept, determining the EI based on the timing of PCIA-eligible resource output aligns the EI inputs with the generation volumes to which the MPB is applied within the PCIA. However, any alternative proposal to the current EI method must maintain transparency and stability so that stakeholders such as CCAs can plan for future PCIA rate changes. If such transparency and stability cannot be maintained, the current EI method should be retained.

2. **Would it be sufficient to continue using Platts data to calculate on-peak and off-peak indices, with the Commission simply updating the percentage weights that each IOU applies to the on- and off-peak indices? Why or why not?**

The use of a third-party market price forecast as the primary input to the EI calculation is critical. Predictions of future market prices are inherently volatile and subject to many assumptions. Relying on a third-party forecast provides non-IOU stakeholders the opportunity to obtain and rely on data for their own analyses that they know will be fundamentally consistent with the ultimate EI calculation. Continued use of Platts data to calculate the on-peak and off-peak indices is reasonable.

The Commission-approved Common PCIA Template currently accommodates only a single value ($/MWh) as the EI input to the Indifference Amount calculation. In other words, the template applies a weighted average annual $/MWh price for energy to all PCIA resource output for the forecast year. As described in more detail in response to question 7, a single EI can be derived using monthly on- and off-peak generation ratios and monthly Platts forward market prices. Revising the form of the EI input to the PCIA (*e.g.*, 12 monthly prices rather than one annual price) would require revisiting the Common PCIA Template design.

3. **Platts data are proprietary. Are there non-proprietary data sources that could result in an Energy Index of equal or better quality than the current Energy Index? If so, what are those data sources?**

CalCCA is unaware of any non-proprietary data sources produced with the same frequency or data inputs as Platts. According to S&P Global Platts' methodology and specifications guide, the Platts forward market price curves rely primarily on Intercontinental Exchange (ICE) settlement and intra-day forward trading activity in the Electricity markets on the ICE platform. Platts has the exclusive right to use ICE intra-day and end of day data for purposes of forward curve derivation.

4. **If only proprietary data sources would result in an Energy Index of equal or better quality than the current Energy Index, what are those data sources?**

Several vendors publish forward market price curves, with near term prices generally linked to observed forward market transactions. For example, through its subscription to the S&P Global Capital IQ platform, NewGen has access to electricity futures prices published by Tradition, BGC Partners, and CME Group (NYMEX). Electricity price forecasts are available for purchase through other firms specializing in modeling energy markets. Neither CalCCA nor NewGen has performed any analysis to determine whether these or other data sources are of equal or better quality than Platts data.

5. **Is there a cost to obtain any of the data you identified in your responses above? If so, what is the cost?**

In CalCCA's experience, there is a cost to obtain forward price curves that rely on proprietary data from brokers or exchanges. Because the price often varies by purchaser or use case, CalCCA is not able to estimate the cost of any proprietary data source.

6. **Based on the data sources you identified in your responses above, discuss the benefits and drawbacks of the following entities calculating the Energy Index, in terms of cost, efficiency, and transparency:**

    a. **Energy Division staff**

    b. **The IOUs**

    c. **A third-party consultant**

Cost: Assuming Energy Division's subscription to Platts includes access to monthly forward market prices, there should be no incremental direct cost to Staff to implement CalCCA's proposal. Each year, the IOUs will be required to summarize PCIA-eligible resource output on a monthly on- and off-peak basis and provide the monthly percentage weights to stakeholders.

The weights should be provided in the workpapers accompanying the annual ERRA Forecast applications. There is no incremental cost to third-party consultants.

Efficiency: The process and timeline for Energy Division to calculate the forecast EI would remain largely intact, except that monthly market forwards would be gathered from Platts. Once an initial template is established to incorporate monthly price data, Energy Division could publish the EI with the same efficiency as the current process. The IOUs would be required to gather historical generation data on an annual basis and update the historical generation weights for inclusion in their annual ERRA Forecast filings, following the same process used to currently to update bundled load weightings.

Transparency: Relying on historical generation data provides assurance to all stakeholders, including those who cannot access confidential IOU data, that the inputs to the EI are an accurate representation of the utility's PCIA portfolio. Using a multi-year average smooths out volatility in the on- and off-peak ratios, and those ratios can be made available to the public, both of which facilitate stakeholder planning.

7. **How will the Energy Index and any related weights be calculated? Describe the data sources, the data scope (e.g., which months or years of data will be used, as applicable), the timing of calculations prior to the October Update, and the calculation methodology for both the Energy Index itself and any weights.**

CalCCA proposes to calculate the EI MPB by multiplying monthly on- and off-peak forward market prices (NP15 for PG&E and SP15 for SCE and SDG&E) by the historical percentage of PCIA-eligible resource generation in monthly on- and off-peak periods. The generation weights that apply to the Platts on- and off-peak forward market price would be derived based on a rolling average of historical monthly PCIA generation output. Specifically, five years of monthly on- and off-peak generation from PCIA-eligible resources would be used to calculate on-and off-peak percentages for each month. Each monthly percentage is multiplied by the corresponding monthly on- and off-peak forward market price from Platts, using monthly forward curves gathered via the same methodology and timing as is currently used for the annual forward price forecast. The monthly weighted prices are converted to an annual EI by multiplying each price by the proportion of generation output in the month relative to a full year of generation output.

Tables 4 - 6 below demonstrate CalCCA's proposal using historical generation output from 2017 – 2021 for each IOU and actual CAISO market prices during 2021. An annual load weighted market price using data from the same period is provided for comparison:

Table 4 – PG&E Monthly Generation Weighted 2021 Market Price

Monthly Energy Index

	PG&E PCIA Generation		Weight			CAISO NP-15		
Month	**On Peak**	**Off Peak**	**Monthly**	**On Peak**	**Off Peak**	**On Peak**	**Off Peak**	**Weighted Price**
1	[redacted]		8%	61%	39%	35.46	31.46	33.88
2			7%	63%	37%	67.80	48.45	60.72
3			8%	63%	37%	32.93	33.19	33.03
4			8%	63%	37%	35.06	36.28	35.51
5			8%	62%	38%	37.00	34.74	36.13
6			9%	65%	35%	56.01	42.50	51.29
7			10%	62%	38%	76.72	55.15	68.62
8			10%	65%	35%	65.57	53.61	61.34
9			9%	61%	39%	71.47	60.37	67.18
10			8%	65%	35%	70.30	61.19	67.13
11			7%	61%	39%	62.20	54.63	59.29
12			8%	60%	40%	67.01	55.39	62.36
								53.51

Annual Energy Index

Generation Weighted						**53.51**
Load Weighted	59%	41%	56.37	47.24		52.59

Table 5 – SCE Monthly Generation Weighted 2021 Market Price

Monthly Energy Index

	SCE PCIA Generation		Weight			CAISO SP-15		
Month	**On Peak**	**Off Peak**	**Monthly**	**On Peak**	**Off Peak**	**On Peak**	**Off Peak**	**Monthly Price**
1	[redacted]		7%	62%	38%	33.22	30.00	32.00
2			7%	65%	35%	71.09	56.32	65.94
3			8%	66%	34%	29.91	31.27	30.38
4			9%	66%	34%	28.04	33.38	29.85
5			10%	64%	36%	26.59	29.92	27.78
6			10%	66%	34%	56.06	41.34	51.10
7			10%	64%	36%	78.89	54.05	70.01
8			10%	67%	33%	65.08	51.40	60.55
9			9%	64%	36%	72.09	58.59	67.22
10			7%	67%	33%	57.89	55.65	57.14
11			6%	64%	36%	60.14	51.68	57.11
12			6%	62%	38%	63.40	53.82	59.80
								50.58

Annual Energy Index

Generation Weighted					**50.58**
Load Weighted	62%	38%	53.41	45.51	50.40

Table 6 – SDG&E Monthly Generation Weighted 2021 Market Price

Monthly Energy Index

	SDG&E PCIA Generation		Weight			CAISO SP-15		
	On Peak	**Off Peak**	**Monthly**	**On Peak**	**Off Peak**	**On Peak**	**Off Peak**	**Monthly Price**
1	[redacted]		7%	69%	31%	33.22	30.00	32.21
2			7%	69%	31%	71.09	56.32	66.52
3			8%	67%	33%	29.91	31.27	30.36
4			8%	70%	30%	28.04	33.38	29.63
5			8%	70%	30%	26.59	29.92	27.58
6			9%	72%	28%	56.06	41.34	51.88
7			10%	69%	31%	78.89	54.05	71.25
8			11%	70%	30%	65.08	51.40	61.04
9			9%	67%	33%	72.09	58.59	67.61
10			8%	67%	33%	57.89	55.65	57.16
11			7%	67%	33%	60.14	51.68	57.37
12			6%	69%	31%	63.40	53.82	60.41
								51.75

Annual Energy Index

Generation Weighted					**51.75**
Load Weighted	61%	39%	53.41	45.51	50.30

On a going forward basis, the calculations demonstrated in the preceding tables would be completed under the same schedule currently followed for the forecasted EI.

CalCCA's proposal is consistent with PG&E's earlier comments in the OIR proceeding, advocating for a monthly volume-weighted approach.[11] The difference between PG&E's suggestion and CalCCA's proposal is the reliance on historical generation output to avoid relying on the IOUs' production cost modeling as an input to the EI.

8. Who will calculate the Energy Index and any related weights? For example, will Energy Division staff, the IOUs, or a third-party consultant collect necessary data and perform the calculations?

Energy Division staff will continue to collect the forward market price data and will publish the forecasted EI as monthly on- and off-peak prices for the forecast year. Similar to the current process for bundled load weights, the IOUs will disclose the monthly on- and off-peak generation weights, as shown in Tables 4 – 6, in their annual ERRA Forecast filings. Each IOU will include the historical PCIA-eligible generation with their annual ERRA Forecast applications and will calculate the rolling 5-year average monthly on- and off-peak generation weights.

9. What is the cost of obtaining necessary data and performing the calculations? How will this cost be recovered?

There is no additional cost to Energy Division to obtain the necessary data (assuming Energy Division's current access to Platts data includes monthly market prices). The IOUs will incur additional time each year required to summarize generation data from the prior year and include it in their respective ERRA filings.

10. How would this proposal improve upon the current situation? In answering this question, address the following sub-questions:

a. How will the proposal affect the workload of Energy Division staff?

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[11] *Opening Comments of Pacific Gas & Electric Company on Market Price Benchmark Issue Date,* R.17-06-026 (Sept. 13, 2021), at 5.

CalCCA's proposal should not materially impact Energy Division staff workload, in particular after the first template is finalized.

b. How will the proposal ensure transparency in data sources?

CalCCA's proposal relies entirely on data from an independent third party (Platts) and recorded historical information. Relying on historical generation data provides assurance to all stakeholders, including those who cannot access confidential IOU data, that the inputs to the EI are an accurate representation of the utility's PCIA portfolio.

c. How will the proposal ensure transparency in the calculation methodologies of both the Energy Index itself and any weights applied to the Energy Index?

The most important feature of CalCCA's proposal as it relates to transparency is the use of *historical* PCIA generation output rather than a *forecast* derived within the IOUs' production cost models. In addition, using a multi-year average smooths out volatility in the on- and off-peak ratios, and those ratios can be made available to the public, both of which facilitate stakeholder planning.

Transparency into PCIA rates is critical for CCAs and other entities serving departing load customers. One of the benefits of the current EI calculation is that each party can obtain the inputs to the MPB without relying on the IOUs or dealing with confidential market sensitive data. If, instead, the current calculation is replaced by each IOU's forecast of wholesale market revenue based on its own production cost modeling, this benefit will be lost. Stakeholders will not have access to the data driving the annual EI, with the limited exception of a reviewing representative within the confines of an ERRA proceeding, removing any ability to plan for changes to the PCIA.

d. Show how PCIA rates and PABA balances would have changed if the 2020 Forecast Energy Index, the 2021 Forecast Energy Index, and the 2022 Forecast Energy Index had all been calculated using the proposed methodology, while keeping all other components of the calculations unchanged. This analysis should include public versions of existing ERRA workpapers that calculate indifference amounts, PCIA rates by customer class and vintage, and PABA balances for easy comparison to actual workpapers in past ERRA proceedings. It should also include a written description of the quantitative impacts resulting from the recalculation of the indifference amount.

Question 10d. is not applicable to parties other than the IOUs, as directed in the Ruling.[12]

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission adopt this proposal to calculate the EI and looks forward to an ongoing dialogue with the Commission and stakeholders with regard to its proposal.

Respectfully submitted,

/s/ Brian Dickman
Brian Dickman,
Partner

NEWGEN STRATEGIES AND
SOLUTIONS, LLC

On behalf of
California Community Choice Association

June 13, 2022

[12] Ruling at 5 ("[a]ny other party [other than the IOUs] may also file an Energy Index MPB calculation proposal that answers all of the questions above (except for question 10(d) . . .").

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

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

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June 14, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. HOURLY TRANSACTIONS OF LOAD OBLIGATIONS AND RESOURCES 1

- A. The Commission Must Recognize Hourly Trading of Resources and Load Obligations is Critical to Maintaining an Affordable RA Program 1
- B. The Timeline Established in the PD Provides Sufficient Time to Incorporate Hourly Trading Into the 24-Hour Framework 2
- C. Hourly Trading is Compatible with Other Proceedings, Including the PCIA and ERRA 2
- D. The CAISO's Comments on Deliverability Highlight that Party Concerns Around Complexity are not Driven by Hourly Trading 3

III. SCOPE OF THE WORKSTREAMS 3

- A. The Commission Should Continue to Include Flexible RA in the Workstreams 3

IV. LOCAL CAPACITY REQUIREMENTS 4

- A. CEJA Correctly Requests the Commission to Consider How to Align the IRP Proceeding with LCR Needs 4

V. PLANNING RESERVE MARGIN 4

- A. The PD Correctly Declines to Update the PRM Based on Disputed Study Results 4
- B. Regular Updates to the PRM Require a Balance that Maintains Regulatory Certainty and Avoids Excess Procurement While Meeting Reliability Targets 5

VI. CONCLUSION 5

SUMMARY OF REPLY COMMENTS

- ✓ The California Public Utilities Commission (Commission) must adopt hourly trading of resources and load obligations is critical to maintaining an affordable Resource Adequacy (RA) program;
- ✓ The timeline established in the PD provides sufficient time to incorporate hourly trading into the 24-hour framework;
- ✓ Hourly trading is compatible with other proceedings, including the Power Charge Indifference Adjustment (PCIA) and Energy Rate Recovery Account (ERRA) proceedings;
- ✓ The California Independent System Operator Corporation's (CAISO) comments on deliverability highlight that party concerns around complexity are not driven by hourly trading;
- ✓ The Commission should continue to include flexible RA in the workstreams;
- ✓ The California Environmental Justice Alliance correctly requests the Commission to consider how to align the Integrated Resource Planning (IRP) proceeding with Local Capacity Requirement (LCR) needs;
- ✓ The PD correctly declines to update the Planning Reserve Margin (PRM) based on disputed study results; and
- ✓ Regular updates to the PRM require a balance that maintains regulatory certainty.

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

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these Reply Comments pursuant to Rule 14.3(d) of the Commission's Rules of Practice and Procedure on the proposed *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework* (PD), issued on May 20, 2022.

II. HOURLY TRANSACTIONS OF LOAD OBLIGATIONS AND RESOURCES

A. The Commission Must Recognize Hourly Trading of Resources and Load Obligations is Critical to Maintaining an Affordable RA Program

PG&E opposes hourly trading of obligations or resources.[2] Precluding hourly trading will drive-up RA costs by ignoring diversity effects and artificially constraining the RA market. As PCE, SJCE, and the CESA correctly note in their comments, giving load serving entities (LSEs) the option to either (1) procure 24-hour strips of RA capacity or (2) procure new storage capacity to cure shortfalls in individual hours will raise RA costs and prohibit LSEs from optimizing the full value of existing RA capacity and new clean resources.[3]

PG&E's position fundamentally ignores the affordability impacts of restricting hourly trading. PG&E asserts that hourly resource and load obligation trading would, "…create a disincentive to create innovative clean energy technologies and products because a [LSE] that might fill a requirement gap, in the middle of the night for example, with a new DR program or a storage technology under a no trading scenario could simply fill that need via a contract with an existing gas plant under an hourly resource or obligation trading scenario."[4] First, the IRP proceeding, not the RA program, should incentivize new clean resource build and has done so ordering significant procurement by 2026 that will be met with

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Pacific Gas and Electric Company (PG&E) Opening Comments at 3-4.

3 Peninsula Clean Energy (PCE), San José Clean Energy (SJCE), and California Energy Storage Alliance CESA) Opening Comments at 4 (all references to party Opening Comments are to the comments filed in this Docket in response to the PD on June 9, 2022).

4 PG&E Opening Comments at 4.

storage and other clean energy resources.[5] The RA program, on the other hand, is in place to ensure those clean resources built through the IRP are under contract and available to meet reliability targets. Artificially constraining the RA market by not allowing hourly load obligation trading and hourly resource trading will simply result in over-procurement of RA, which will drive up market prices at the expense of ratepayers. Contrary to PG&E's assertions, duplicative procurement necessitated by restricting transactability may result in the inability to retire polluting resources, not the creation of clean technologies, because the resources must be maintained simply to satisfy a compliance obligation rather than a reliability need.

B. The Timeline Established in the PD Provides Sufficient Time to Incorporate Hourly Trading Into the 24-Hour Framework

PG&E,[6] SCE,[7] and MRP[8] incorrectly suggest that incorporating hourly trading of either resources or load obligations would introduce significant additional complexity and would delay implementation of the 24-hour framework.[9] Multiple parties including CalCCA have outlined detailed proposals for both hourly load obligation trading and hourly resource trading. Any additional mechanical details needed to implement these proposals can be addressed in the workstreams and further refined as needed during the test year in 2024. Hourly trading is a critically important ***and*** readily achievable component of a 24-hour framework and should be prioritized in the workstreams to ensure its implementation for the 2025 RA year with the rest of the 24-hour framework.

C. Hourly Trading is Compatible with Other Proceedings, Including the PCIA and ERRA

PG&E's comments suggest the PD should reject hourly resources and load obligation trading because hourly trading would require changes in other rate-making proceedings, such as updating the RA market price benchmarks (MPBs) to hourly within the PCIA and ERRA proceedings.[10] As an initial matter, concerns around impacts to the PCIA and ERRA proceedings were not raised in this proceeding until PG&E's opening comments.[11] Setting aside the procedural defect, PG&E's concerns are not well

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5 Decision (D.) 21-06-035, *Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026)*, Rulemaking (R.) 20-05-003 (June 30, 2021).

6 PG&E Opening Comments at 3-4.

7 Southern California Edison Company (SCE) Opening Comments at 4.

8 Middle River Power LLC (MRP) Opening Comments at 13-14.

9 PG&E and MRP express concern with both hourly obligation trading and hourly resource trading, while it appears SCE's concerns are limited to hourly resource trading only.

10 PG&E Opening Comments at 3.

11 *Reply Comments of Pacific Gas and Electric (U 39 E) on the RA Reform Working Group Report*, R.21-10-002 (Apr. 1, 2022), at 8.

grounded. Currently, RA is traded on a monthly basis while the RA MPB is based upon an annual value for both the forecast and true-up. Therefore, it is not clear that it is immediately necessary to update the RA MPBs for hourly trading.

D. The CAISO's Comments on Deliverability Highlight that Party Concerns Around Complexity are not Driven by Hourly Trading

The PD declines to adopt hourly trading in part to concerns around added complexity to the CAISO processes. The CAISO's opening comments, however, demonstrate that the source of added complexity is *not* hourly trading, as the PD suggests, but rather the 24-hour framework in itself. The CAISO supports further exploration of how deliverability would work under a 24-hour framework in workstream three because it is not clear to the CAISO whether considering a single hour when assessing deliverability is sufficient under a 24-hour framework. While the CAISO and the PD attempt to justify foregoing hourly trading by citing changes that would be needed to deliverability, the CAISO itself suggests changes may be needed to its deliverability methodology to consider more hours under the 24-hour framework, even if hourly trading is not adopted.[12] Therefore, the Commission must not reject transactability on this basis.

III. SCOPE OF THE WORKSTREAMS

A. The Commission Should Continue to Include Flexible RA in the Workstreams

The CAISO recommends the Commission remove the discussion of flexible capacity from the scope of workstream three.[13] CalCCA disagrees with this recommendation. The original flexible RA program was designed in close coordination between the CAISO and the Commission. Upon completion of the CAISO stakeholder process, the CAISO's proposal was brought to the Commission for its adoption.[14] This collaborative approach should be taken when considering the need for the flexible RA under the new framework.

Public Utilities Code section 380 gives the Commission the authority, in consultation with the CAISO, to establish the resource adequacy requirements for LSEs.[15] The PD acknowledges the CAISO's current tariff and processes will need to align with the removal of the flexible RA requirements, and appropriately puts the elimination of flexible RA in the "CAISO Coordination" workstream to ensure that the discussion around the future of flexible RA can be coordinated with the

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12 CAISO Opening Comments at 7.

13 *Id.*

14 D.14-06-050, *Decision Adopting Local Procurement and Flexible Capacity Obligations For 2015, and Further Refining the Resource Adequacy Program*, R.11-10-023 (July 1, 2014).

15 Cal. Pub. Util. Code § 380.

CAISO's own stakeholder process. [16] For these reasons, the Commission should maintain discussion around the need for flexible RA in the workstream.

IV. LOCAL CAPACITY REQUIREMENTS

A. CEJA Correctly Requests the Commission to Consider How to Align the IRP Proceeding with LCR Needs

The PD indicates that the LCR working group process resulted in no recommendations to modify the LCR criteria or process.[17] This statement is in error. CalCCA's comments to the LCR working group report recommended the Commission consider how to better align the IRP and RA processes such that new resource build aligns with the local RA need.[18] CEJA states, "Increased coordination between LCR evaluations and IRP procurement is critical to ensure that new resources are located in areas where they are most effective."[19] CalCCA agrees with CEJA. The disconnect between IRP and the LCR process will lead to inefficient procurement given the lack of information around the effectiveness factors of new resources. The Commission should consider how its IRP and RA processes can provide a means to assess the effectiveness of new resources at meeting local needs.

V. PLANNING RESERVE MARGIN

A. The PD Correctly Declines to Update the PRM Based on Disputed Study Results

Several parties[20] suggest the PD be revised to increase the PRM beyond the 16 percent for 2023 and at least 17 percent for 2024 adopted in the PD. These parties cite to the 22.5 percent PRM adopted in the IRP proceeding or the Energy Division (ED) Loss of Load Expectation (LOLE) Study results in the RA proceeding that resulted in a roughly 20 percent PRM. First, the 22.5 percent number adopted in the IRP proceeding resulted in an LOLE that was far lower than the 1-in-10 standard typically used for reliability planning.[21] Second, as the PD correctly notes, numerous parties express concern around the inputs and assumptions used in the LOLE study within the RA proceeding and request additional information or adjustments be made prior to the adoption of the study results.[22]

The PD strikes the right balance by adopting a small increase in the PRM for 2023 and 2024, with the ability to modify the PRM for 2024 following the additional modeling taking place in the IRP

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16 PD at 99.

17 *Id.* at 9.

18 CEJA Opening Comments at 2.

19 *Id.*, at 1.

20 Calpine Corporation, Western Power Trading Forum, Vistra Corps., and MRP.

21 D.22-02-004, *Decision Adopting 2021 Preferred System Plan*, R.20-05-003 (Feb. 15, 2022).

22 PD at 17-18.

proceeding. A robust modeling process that allows parties to fully understand and vet the results is critical in adopting a PRM that meets the 1-in-10 reliability standard. The PD establishes the appropriate steps for ensuring this process can take place before taking further steps to modify the PRM.

B. Regular Updates to the PRM Require a Balance that Maintains Regulatory Certainty and Avoids Excess Procurement While Meeting Reliability Targets

Vistra Corps' comments reiterate its support for establishing the RA requirements through an annual LOLE study.[23] CalCCA supports a regular LOLE study process to assess the PRM's ability to meet the 1-in-10 reliability target. To accomplish this, LOLE studies should be updated regularly to reflect changes to study inputs. As discussed in CalCCA's comments to ED's LOLE study, an annual LOLE study should only result in updates to the PRM if there are significant changes to the results and with enough time for parties to vet the results and for LSEs to plan and conduct orderly procurement to meet the new PRM.[24] This will provide needed certainty to LSEs in their planning and procurement. Additionally, NRDC recommends the Commission modify the PD to require workstream two to develop monthly PRM values.[25] This recommendation merits further discussion within the workstreams to examine the applicability of monthly differentiated PRMs to avoid excess procurement.

VI. CONCLUSION

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

Respectfully submitted,

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

June 14, 2022

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23 Vistra Opening Comments at 6.

24 *California Community Choice Association's Comments on the Local Capacity Requirement (LCR) Final Working Group Report And Energy Division's Loss Of Load Expectation Study*, R.21-10-002 (March 14, 2022), at 10-11.

25 Natural Resources Defense Council (NRDC) Opening Comments at 2.

June 27, 2022

VIA ELECTRONIC MAIL

Mr. Simon Baker
Interim Director, Energy and Climate Policy
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: California Community Choice Association's Comments on Draft Resolution E-5127 Regarding Procedures for the Large Energy Utilities' Annual Year-End Consolidated Electric Revenue and Rate Change Filings

Dear Mr. Baker:

Pursuant to Rule 14.5 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the accompanying Comment Letter to Draft Resolution E-5127, California Community Choice Association[1] (CalCCA) submits these comments in support of Draft Resolution E-5127 (Draft Resolution), dated July 14, 2022.

1. SUMMARY

CalCCA strongly supports the draft resolution as a step in the right direction towards implementation of rates in a timely, coordinated and transparent manner. Two adjustments to the Draft Resolution will give all affected ratepayers the best opportunity to understand, communicate, and plan for the rates customers will pay on the first of the year:

- Require the provision of public workpapers in their native format, *i.e.*, an Excel spreadsheet, contemporaneously with service of the advice letters themselves; and
- Require the provision of confidential workpapers to qualified reviewing representatives (RRs) within five calendar days of a party requesting them.

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Adopting the modest modifications suggested in Appendix A to these comments will help ensure the Draft Resolution's goals are met for all ratepayers.

2. SMALL MODIFICATIONS TO THE DRAFT RESOLUTION WILL HELP ENSURE EFFICIENT AND TRANSPARENT RATE CHANGES

The Draft Resolution makes welcome strides toward more transparent, efficient and consistent rate changes; enacting revisions for which community choice aggregators (CCAs) have long clamored.[2] A November 5th filing date for the Tier 2 advice letters will bring the timing of Pacific Gas and Electric Company's (PG&E's) Annual Electric True-Up (AET) and San Diego Gas & Electric Company's (SDG&E's) consolidated rate change in line with Southern California Edison's (SCE's) more reasonably timed advice letter.[3]

Including regulatory account balances for electric revenue accounts through November 30, and projected balances through December 31, will result in less volatile rates the following year. That approach builds on a successful process initially required by Judge Susan Lee and Energy Division in PG&E's 2022 ERRA forecast proceeding (Application (A.) 21-06-001) via a ruling that required PG&E to update its forecasted generation rates with actual data from October and November.[4] SCE also has included year-to-date actuals in its advice letter implementing its ERRA forecast proceeding (A.22-05-014), although such implementation typically has taken place after the first of the year.[5] Utilizing as many "actuals," *i.e.*, actual recorded volumes and revenues, to set rates at the end of one year decreases the need to true such rates up the following year.

The data required to be provided as part of the November 5 Tier 2 advice letter is also helpful. Increasing transparency via (1) a summary of each revenue requirement for individual unbundled rate components, (2) an explanation for each revenue requirement change, and, in particular, (3) workpapers supporting rate change and revenue allocation, and revised tariffs schedules will aide non-investor-owned utility (IOU) parties in anticipating and understanding these rate changes. Such understanding will not only benefit departed customers but also reduce

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[2] *See*, *e.g.*, Joint CCAs' Response to Pacific Gas and Electric Company's Advice Letter 5661-E (Nov. 4, 2019) (stating "The Advice Letter also reflects on-going consistency and transparency issues common across all PG&E's showings with respect to the AET, ERRA and trigger advice letters. The Joint CCAs here again note the difficulty unbundled customers face in understanding their 2020 rates in a reasonable timeframe. The inconsistencies between the utility's AET and trigger advice letters and its testimony and discovery responses in the ERRA proceeding continue to drive the need for more timely, consistent and transparent data.").

[3] *See* Draft Resolution at 2-3.

[4] E-Mail Ruling Ordering Additional Updates with Amended Schedule, A.21-06-001 (Nov. 24, 2021), at 3 (directing PG&E to file updated testimony in December and postponing a final decision until January 13, 2021).

[5] *See* Draft Resolution at 5. Decision (D.) 22-01-023 requires SCE to shift its approach to a January 1 implementation for the first time this year.

administrative burdens in resolving protests to the advice letters, especially when such protests result from a lack of access to the data underlying the rate changes.

While these changes will "provide a more efficient process" to implement these revenue requirements and reduce confusion for customers and non-IOU load-serving entities (LSEs) alike,[6] the Commission should consider the following three further changes to ensure the Draft Resolution's goals are met.

3. REQUIRE THE IOUS TO PROVIDE PUBLIC WORKPAPERS IN THEIR NATIVE FORMAT AND CONFIDENTIAL WORKPAPERS WITHIN FIVE CALENDAR DAYS

The Draft Resolution makes an important conclusion that parties need adequate time to verify the information in the IOUs' advice letters and perform discovery.[7] General Order 96-B's 20-day timeline for protests makes that task difficult to achieve in light of the Commission's customary 10 business-day deadline for discovery responses, which typically translates to a 14-calendar-day deadline, taking up nearly 75 percent of the protest period on its own.

Adding to these difficulties is that a November 5th deadline can include three Commission holidays before the protest date: Veterans Day (November 11), Thanksgiving Day (November 24), and the day after Thanksgiving (November 25), using this year's dates as an example. The result in years such as this one is a due date for a response to a data request (DR) seeking workpapers, served three days after the advice letters are submitted, that carries the same due date as the protest itself. A DR served the day after the advice letters are submitted would only leave one business day (November 23) for parties to draft a protest alerting the Commission of any errors. Such timelines do not meet the goals laid out in the Draft Resolution.

A solution to this problem can be derived from the Draft Resolution's requirement for the IOUs to include "workpapers supporting rate change and revenue allocation" and ensure parties have access to the data underlying the advice letters in a timely manner.[8] First, public workpapers should be provided in Excel format instead of, or in addition to, PDF format as part of the service of the advice letters. Such a requirement will preclude the need for parties unable or unwilling to sign a non-disclosure agreement (NDA) to request those documents in a workable format that supports analysis of the data.

Second, the IOUs should be required to provide confidential versions of those workpapers to qualified RRs within five calendar days of a party requesting them, provided that an RR has executed the appropriate NDA on that party's behalf. Since the Draft Resolution would require these same materials be provided to Commission staff five days prior, providing the materials to RRs should not be a difficult task for the IOUs. In fact, the five-calendar-day

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[6] Draft Resolution at 1.
[7] *Id.* at 5.
[8] *Id.* at OP 4.e.

timeline will allow the requesting party and the IOU to go through the process of reviewing RRs and providing the applicable NDA for execution.

4. CONCLUSION

CalCCA appreciates the Commission's thoughtful and careful consideration of these comments on Draft Resolution E-5127.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl,

Evelyn Kahl

General Counsel and Director of Policy

cc via email:

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Service List: A.21-06-021, A.19-08-013, A.22-05-016, A.17-10-007

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON DRAFT RESOLUTION E-5127 REGARDING PROCEDURES FOR THE LARGE ENERGY UTILITIES' ANNUAL YEAR-END CONSOLIDATED ELECTRIC REVENUE AND RATE CHANGE FILINGS

Findings

8. Providing public workpapers in their native format as part of service of the advice letters, and confidential versions of the workpapers to non-utility reviewing representatives within five calendar days of a request for such workpapers, will ensure parties have adequate time to verify the information in the IOUs' advice letters.

Ordering Paragraphs

4. At a minimum, the consolidated electric rate change ALs shall include the following information:

   a. A summary of each revenue requirement component, the current revenue requirements, January 1 revenue requirements, change in revenue requirements, and associated authority for change.
   b. A summary of each revenue requirement for individual unbundled rate components.
   c. An explanation for each revenue requirement change.
   d. Estimated rate and residential bill impacts without climate credit.
   e. Public workpapers in their native format, *i.e.*, an Excel spreadsheet, supporting rate change and revenue allocation, served contemporaneously with the advice letters themselves.
   f. Revised tariffs schedules.

5. PG&E, SCE and SDG&E shall provide confidential versions of the workpapers supporting the advice letter to non-utility reviewing representatives within five calendar days of a request for such workpapers, provided such reviewing representative has executed the applicable nondisclosure agreement.

California Community Choice Association

SUBMITTED 06/28/2022, 03:35 PM

Contact

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

1. Provide a summary of your organization's comments on the Interconnection Process Enhancements (IPE) 2021 – Phase 2 revised straw proposal:

CalCCA generally supports the California Independent System Operator Corporation's (CAISO's) Interconnection Process Enhancements (IPE) Phase 2 Revised Straw Proposal. This initiative comes at a critical point when load-serving entities (LSEs) are expanding procurement activities at a rapid pace to meet procurement orders and state clean energy policies. As a result, the CAISO interconnection queue is experiencing an unprecedented number of study requests. Proposals that can reduce interconnection queue backlog and prioritize the most viable projects when allocating deliverability will enhance the ability of LSEs to conduct procurement of new resources and the CAISO to conduct studies on new projects in a timely and orderly manner. Such proposals must balance (1) the need to get the most viable projects through the queue in a timely and orderly manner that can support grid reliability and state policy goals, and (2) the ability for all prospective projects to be able to compete for power-purchase agreements (PPAs) with LSEs.

Planning Resource Adequacy (RA) procurement in the context of deliverability creates a "chicken and egg" problem. Today, the interconnection queue holds 10 to 15 times more megawatts (MW) than what is needed to meet procurement orders.[1] LSEs face challenges narrowing down the number of projects available to contract because not all the projects in the queue will obtain the deliverability status needed to provide RA. At the same time, the CAISO faces challenges when narrowing down which projects to study for and allocate deliverability to using the limited time and staff resources available. Two solutions are available. The CAISO can assign deliverability to projects, signaling to LSEs to sign PPAs with those projects. Alternatively, developers can contract with LSEs first, then the CAISO can assign deliverability to those projects with PPAs. The CAISO's proposal aims at advancing the second approach.

The CAISO's proposal to prioritize projects with PPAs that sell RA attributes for a minimum term will help ensure deliverability is allocated to the projects most likely to reach commercial operation and provide reliability to California. In these comments, CalCCA supports the requirement for PPAs to have a minimum term and asks additional clarifying questions to ensure projects can be reallocated in the event a project with a PPA fails such that LSEs can meet their procurement orders with deliverable projects.

In summary, CalCCA:

- Does not object to the data items in section 3.3 being made public so long as counterparties to PPAs are *not* identified publicly;
- Supports a minimum PPA term with a contract for RA capacity of 10 years to be put in the highest priority allocation group;
- Supports requiring entities without an RA obligation to have a contract with an LSE with an RA obligation prior to being placed in the highest allocation group for Transmission Plan Deliverability (TPD); and
- Supports higher deposit fees that will encourage developers to submit a reasonable number of interconnection requests for high-quality projects.

[1] CAISO Revised Straw Proposal at 5.

2. Please comment on section 3.3 - Transparency enhancements: Which data items do you support being public?

No comments at this time.

3. Please comment on section 3.3 - Transparency enhancements: Which data items do you support not being public and why?

CalCCA does not object to the items in section 3.3 being public so long as the "PPA executed and MW" item on Slide 12 would *not* make the counterparty(ies) to the PPA public, as releasing this information would raise competitiveness concerns.

4. Please comment on section 3.3 - Transparency enhancements: Are there other data items you would like to see as public information?

No comments at this time.

5. Please comment on section 3.3 - Transparency enhancements: What are your thought on allowing Interconnection Customers to make their data public?

No comments at this time.

6. Please provide comments on the following question related to section 3.4: Revisiting the criteria for PPAs to be eligible for a Transmission Plan Deliverability (TPD) allocation: a) Should the allocation of TPD require a PPA that procures the project's RA capacity for some minimum term? Please provide reasoning supporting your answer. b) If yes, what should that minimum term be and what is the basis for that?

Yes, the allocation of TPD should require a PPA that procures the project's RA capacity for a minimum term. CalCCA understands that this requirement would not preclude projects that do not meet this requirement from getting TPD. Rather, it would prioritize those projects with PPAs with RA capacity for a minimum term in allocation group A, above those PPAs without procuring RA capacity for at least the minimum term. The CAISO should clarify if and how, in the event a project in allocation group A fails, other projects would be reprioritized within the allocation groups. For example, if a project with a PPA fails and the LSE executes a new PPA with another project, does that new project get placed in allocation group A, effectively replacing the failed project? This clarification is important because LSEs need to be able to determine which projects to pursue to have the best chances of obtaining TPD and - in turn - meet procurement orders in the event a prior project fails.

The minimum term should reflect the standard term of PPAs many CCAs are encountering for new resources, which is 10 years. Minimum term requirements shorter in length may not have the desired outcome of creating meaningful criteria for getting placed in allocation group A, because a majority of PPAs are for terms of 10 years or longer.

7. Please provide comments on the following question related to section 3.4: Revisiting the criteria for PPAs to be eligible for a Transmission Plan Deliverability (TPD) allocation: a) Should a PPA that is with an entity that does not have an RA obligation be eligible for an allocation if the procuring entity demonstrates that it has a contract to sell the RA capacity procured to a load servicing entity that has an RA obligation? Please provide reasoning supporting your answer. b) If yes, should the procuring entity be given extra time after the project receives an allocation to secure a contract with a load serving entity with an RA obligation? Please provide reasoning supporting your answer. c) If yes, what length of extra time should be provided and what is the basis for that?

A PPA with an entity that does not have an RA obligation should be eligible for an allocation of TPD only if the procuring entity demonstrates it has a contract with an LSE that has an RA obligation. This contract should be in place at the time of the deliverability allocation. Because LSEs are the ones with the RA obligations, the capacity they have under contract should be first in line to receive allocations of deliverability. This rationale is consistent with the Maxim Import Capability (MIC) process, in which MIC is allocated to LSEs first (the ones with the RA obligation) and then to others.

8. Please comment on section 4.1: Should higher fees, deposits, or other criteria be required for submitting an IR?

CalCCA supports the CAISO's proposal to increase study deposits to encourage a more reasonable number of interconnection requests.

9. Please comment on section 5.1: Should the ISO re-consider an alternative cost allocation treatment for network upgrades to local (below 200 KV) systems where the associated generation benefits more than, or other than, the customers within the service area of the Participating TO owning the facilities?

No comments at this time.

10. Please comment on section 5.2: Policy for ISO as an Affected System – a) How the base case determined b.) How required upgrades are paid for:

No comments at this time.

11. Please comment on section 5.3: While the tariff currently allows a project to achieve its COD within seven (7) years if a project cannot prove that it is actually moving forward to permitting and

construction, should the ISO have the ability to terminate the GIA earlier than the seven year period?

No comments at this time.

12. Please comment on section 5.3: Do you have any concerns with the ISO's proposed implementation?

No comments at this time.

13. Please comment on section 5.3: Are there other opportunities the ISO should consider with respect to projects not moving through the queue?

No comments at this time.

14. Please comment on section 6.2: Examining the issue of when a developer issues a notice to proceed to the PTO, requesting the PTO/ISO should start planning for all upgrades that are required for a project to attain FCDS, including the upgrades that get triggered by a group of projects:

No comments at this time.

15. Additional comments on the IPE 2021 revised straw proposal and June 14, 2022, stakeholder workshop discussion particularly focused on any Phase 2 issues:

No comments at this time.

FILED
06/30/22
02:31 PM
R1807006

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION IMPLEMENTING THE AFFORDABILITY METRICS

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June 30, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THE COMMISSION SHOULD ADOPT THE PD'S ESTABLISHMENT OF A MULTI-YEAR IMPLEMENTATION AND ASSESSMENT OF THE EFFECTIVENESS OF THE AFFORDABILITY METRICS..2

III. THE COMMISSION SHOULD ADOPT THE PD'S RELIANCE ON THE CALENVIROSCREEN TOOL AND CALEPA'S DEFINITION OF DACS INSTEAD OF SEVI TO ENSURE CONSIDERATION OF ALL FACTORS IMPACTING AFFORDABILITY..3

IV. CONCLUSION..4

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.20-07-032 2

California Public Utilities Commission Rulemakings

R.18-07-006 .... 1, 2

California Public Utilities Commission Rules of Practice and Procedure

Rule 14.3 1

SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) supports the adoption of the Proposed Decision:

- The PD's establishment of a multi-year period of assessment on the implementation of the Affordability metrics will allow for improvement based on actual experience of the California Public Utilities Commission (Commission) and parties with the metrics; and

- The PD's reliance on the CalEnviroScreen tool and California Environmental Protection Agency's (CalEPA) definition of Disadvantaged Communities (DACs) instead of the Socioeconomic Vulnerability Index (SEVI) will ensure consideration of more factors impacting affordability, including environmental and health factors.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION IMPLEMENTING
THE AFFORDABILITY METRICS

The California Community Choice Association (CalCCA)[1] submits these Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Implementing the Affordability Metrics* (PD or Proposed Decision), issued on June 10, 2022.

I. INTRODUCTION

The PD represents the continuation of the Commission's careful work constructing the metrics and framework to analyze the affordability of essential utility services. As the Covid pandemic continues and other economic and climate impacts continue to challenge Californian households, the Commission's focus on affordability remains more important than ever. Given the complexities concerning the three affordability metrics adopted in the Phase 1 Decision,[2] as

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11 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 D.20-07-032, *Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service,* R.18-07-006 (July 16, 2020).

well as the further refinement proposed by the Staff Proposal on Implementation of Affordability Metrics (Staff Proposal), the Commission should approve the PD's adoption of a multi-year stakeholder feedback process after parties have hands-on experience with the tools and methodologies. This careful approach will ensure that the metrics are continually refined to allow for inputs that will produce an accurate affordability assessment of utility rates and programs for the Commission, stakeholders, and consumers.

For the reasons set forth below, CalCCA supports the PD's adoption:

- The PD's establishment of a multi-year period of assessment on the implementation of the Affordability metrics will allow for improvement based on actual experience of the Commission and parties with the metrics; and
- The PD's reliance on the CalEnviroScreen tool and California Environmental Protection Agency's (CalEPA) definition of Disadvantaged Communities (DACs) instead of the Socioeconomic Vulnerability Index (SEVI) will ensure consideration of both environmental and health factors impacting affordability.

II. THE COMMISSION SHOULD ADOPT THE PD'S ESTABLISHMENT OF A MULTI-YEAR IMPLEMENTATION AND ASSESSMENT OF THE EFFECTIVENESS OF THE AFFORDABILITY METRICS

The Commission should adopt the PD's approach to gradually implementing affordability metrics across relevant proceedings and to ongoing stakeholder feedback as the Commission and stakeholders implement, report on, and update and improve the affordability metrics. The PD adopts the Staff Proposal with certain technical refinements and adopts a process to solicit feedback on implementation of the metrics for a two-year assessment period. The PD also provides specific questions stakeholders will be invited to address after the publication of the annual Affordability Report, to solicit suggested changes regarding: (1) technical changes to the Affordability Ratio (AR) calculator; (2) forecasting on inputs to the calculator; (3) implementation of the metrics and whether the outputs are useful. This two-year period, along with the proposed set of questions, will therefore allow stakeholders time to provide their perspectives on whether the affordability metrics and their implementation across specific proceedings require further modifications.

III. THE COMMISSION SHOULD ADOPT THE PD'S RELIANCE ON THE CALENVIROSCREEN TOOL AND CALEPA'S DEFINITION OF DACS INSTEAD OF SEVI TO ENSURE CONSIDERATION OF ALL FACTORS IMPACTING AFFORDABILITY

The Commission should adopt the PD's reliance on the CalEnviroScreen tool and CalEPA's definition of DACs instead of SEVI. The PD replaces the Staff Proposal's use of SEVI as the third affordability metric with the most recent version of CalEnviroScreen. The PD identifies benefits of CalEnviroScreen that outweigh those of SEVI, including CalEnviroScreen's alignment with the Commission's Environmental and Social Justice (ESJ) Action Plan. CalCCA supports the incorporation of factors outside of socioeconomic factors, such as health and environmental factors, that contribute to affordability issues. For example, high concentrations of pollutants can lead a household to spend more of its discretionary budget on medical costs, thus increasing the affordability burden of utility bills.

CalCCA recognizes the tradeoff of benefits between tools and supports the PD's modification to use the CalEPA's most recent definition of DACs which incorporates additional categories of DACs to CalEnviroScreen 4.0.[3] As an extract from the CalEnviroScreen tool, SEVI provides a more focused view of socioeconomic vulnerability that is not skewed by other

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[3] In May 2022, CalEPA finalized an update to its designation of DACs for the purpose of SB 535, in the following four categories: (1) census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts); (2) census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest five percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts); (3) census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (305 tracts); and (4) lands under the control of federally recognized tribes, with an option for tribes to consult with CalEPA as necessary. *See Final Designation of Disadvantaged Communities Pursuant to Senate Bill 535* (May 2022), located at https://calepa.ca.gov/wp-content/uploads/sites/6/2022/05/Updated-Disadvantaged-Communities-Designation-DAC-May-2022-Eng.a.hp_-1.pdf

variables included in CalEnviroScreen. At the same time, removing those other variables ignores non-socioeconomic factors which can impact affordability at a community level. While the CalEnviroScreen tool does not depend solely on socioeconomic factors, other affordability metrics like the Affordability Ratio and Hours-at-Minimum-Wage complement CalEnviroScreen by providing a focused socioeconomic lens. Implementing all three affordability metrics will result in identifying geographic areas demonstrating a range of financial, environmental, and socioeconomic hardships without imposing a definition of affordability that is too narrow. CalCCA appreciates the Commission's consideration in selecting metrics that complement each other by examining affordability from different angles, acknowledging that our communities are harmed by various financial, social, and environmental factors.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

June 30, 2022

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO DATA ACCESS AND VOLUNTARY ALLOCATIONS IN MARKET PRICE BENCHMARK CALCULATIONS

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On behalf of
California Community Choice Association

June 30, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THE COMMISSION SHOULD ADOPT THE PD'S CONCLUSION THAT THE TIMEFRAME FOR DATA ACCESS WITHIN ERRA PROCEEDINGS IS A MINIMUM OF EIGHT MONTHS DURING THE PENDENCY OF THE PROCEEDING 3

III. PARTICIPATION IN THE PD'S FRAMEWORK FOR PROVIDING CONFIDENTIAL DATA FOR CCA LONG-TERM PCIA FORECASTING SHOULD BE VOLUNTARY 4

IV. THE COMMISSION SHOULD ADOPT THE PD'S EXCLUSION OF VOLUNTARY ALLOCATIONS FROM RPS MPB CALCULATIONS 5

V. CONCLUSION..5

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.20-12-028 3
D.20-12-035 3
D.20-12-038 3
D.21-01-017 3
D.22-01-023 .... 1, 2, 3

California Public Utilities Commision Proceedings

A.20-04-014 3
A.20-07-002 3
A.20-07-004 4
A.20-09-014 3
A.20-10-007 4
R.17-06-026 .... 1, 2

California Public Utilities Commission Rules of Practice and Procedure

Rule 14.3 1

SUMMARY OF RECOMMENDATIONS

- ✓ To prevent evidentiary disputes in future Energy Resource Recovery Account (ERRA) Forecast proceedings, the Commission should adopt the conclusion in the Proposed Decision (PD) that the timeframe for data access within ERRA proceedings is for a minimum of eight months during the pendency of the proceeding;

- ✓ If the Commission adopts the PD's proposed framework for year-round data access for the purposes of long-term power charge indifference adjustment (PCIA) forecasting (instead of California Community Choice Association's (CalCCA's) proposed Non-Disclosure Agreement approach), any participation by community choice aggregators (CCAs) in such process should be voluntary (i.e., CalCCA and/or individual CCAs may choose not to participate and to instead rely on publicly available data for long-term PCIA forecasting);

- ✓ The Commission should adopt the PD's exclusion of Voluntary Allocations from the calculation of the market price benchmark (MPB).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO DATA ACCESS AND VOLUNTARY ALLOCATIONS IN MARKET PRICE BENCHMARK CALCULATIONS

The California Community Choice Association[1] (CalCCA) submits these Comments pursuant to Rule 14.3(a) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Resolving Phase 2 Issues Related to Data Access and Voluntary Allocations in Market Price Benchmark Calculations* (PD), dated June 10, 2022.

I. INTRODUCTION

CalCCA appreciates the Commission's efforts to provide community choice aggregator (CCA) reviewing representatives year-round access to energy resource recovery account (ERRA) data for long-term power charge indifference adjustment (PCIA) forecasting purposes. On balance, however, the PD's numerous requirements for allowing such access may outweigh the relative value of using confidential data for long-term planning purposes. Indeed, with the PD's

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

clarification of the eight-month term of confidential data access for short-term PCIA forecasting needed to anticipate and plan for their own near-term rate changes, CCAs may be better served by developing a database of publicly available information for long-term forecasting. As a result, if the Commission does not adopt CalCCA's original approach to base the methodology on the use of a Non-Disclosure Agreement (NDA),[2] the Commission should modify the PD to make participation in the proposed framework voluntary for CalCCA and individual CCAs.

The Commission should also adopt two of the PD's important conclusions. First, the PD clarifies that the schedule change for ERRA forecast proceedings adopted in Decision (D.) 22-01-023 grants unbundled customer reviewing representatives access to data *for a minimum of eight months out of the year.*[3] This clarification may prevent future discovery disputes among the investor-owned utilities (IOUs) and CCAs. The PD also correctly excludes Renewables Portfolio Standard (RPS) Voluntary Allocation transactions from the calculation of the RPS Adder component of the Market Price Benchmark (MPB).[4]

For the reasons set forth more fully below, CalCCA recommends the following:

- To prevent evidentiary disputes in future ERRA Forecast proceedings, the Commission should adopt the PD's conclusion that the timeframe for data access within ERRA proceedings is a minimum of eight months during the pendency of the proceeding;

- If the Commission adopts the PD's proposed framework for year-round data access for the purposes of long term PCIA forecasting (instead of CalCCA's NDA approach), any participation by CCAs in such process should be voluntary (i.e.,

2 *See Opening Comments of the California Community Association on ALJ Ruling Regarding PCIA Forecasting Data Access,* R.17-06-026 (Dec. 9, 2021), at 2-6 (recommending the use of a simple NDA to allow CCAs whose customers pay the PCIA to access confidential data on a year-round basis for the limited purpose of long-term forecasts of PCIA rates).

3 PD at 7 ("…the current schedule anticipates that the reviewing representatives of ERRA proceeding parties will not have access to confidential ERRA data from January through April each year (4 months)") (citing D.22-01-023, *Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings,* R.17-06-026 (Jan. 27, 2022)).

4 PD at Finding of Fact (FOF) 5, Conclusion of Law (COL) 12.

CalCCA and/or individual CCAs can choose not to participate and to instead rely on publicly available data for long-term PCIA forecasting); and

- The Commission should adopt the PD's exclusion of Voluntary Allocations from the calculation of the MPB.

II. THE COMMISSION SHOULD ADOPT THE PD'S CONCLUSION THAT THE TIMEFRAME FOR DATA ACCESS WITHIN ERRA PROCEEDINGS IS A MINIMUM OF EIGHT MONTHS DURING THE PENDENCY OF THE PROCEEDING

The PD makes an important clarification that the CCAs' ERRA reviewing representatives have access to a minimum of eight months of confidential data under D.22-01-023.[5] The PD reasons that the new May 15 annual deadline for utilities to file ERRA forecast applications will increase access to confidential data.[6] It states that the current schedule of the ERRA Forecast proceeding "anticipates that the reviewing representatives of ERRA proceeding parties will not have access to confidential ERRA data from January through April each year (4 months)," meaning data will be provided during the remaining eight months.[7] This conclusion, alone, clarifying that access is provided for a minimum of eight months during the pendency of ERRA proceedings, may reduce the potential for future evidentiary disputes.[8] The Commission should adopt the PD's conclusion on the timeframe for data access in ERRA proceedings.

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5 *Id.* at 7.

6 *Id.*

7 *Id.*

8 For example, in last year's (in 2021 for the following year) PG&E ERRA forecast case (A.21-06-001), PG&E objected to a CCA data request *during the pendency of a proposed decision*, despite D.20-12-028's and D.22-01-023's requirement that PG&E provide the confidential data while an ERRA forecast case is *still pending*. *See* D.20-12-038, *Decision Adopting Pacific Gas and Electric Company's 2021 Energy Resource Recovery Account Forecast, Generation Non-Bypassable Charges Forecast, Greenhouse Gas Forecast Revenue Return and Reconciliation, and Related Calculations and Rate Proposals,* A.20-07-002, A.20-09-014 (Dec. 17, 2020), COL 14; *see also* D.22-01-023, COL 7, OP 5. Similar conclusions exist in the other IOUs' 2021 ERRA Forecast Decisions. *See* D.21-01-017, *Decision Adopting 2021 Electric Procurement Revenue Requirement Forecasts and Greenhouse Gas-Related Forecasts for San Diego Gas & Electric Company,* A.20-04-014 (Jan. 14, 2021), at OP 6; *see also* D.20-12-035, *Decision Adopting Southern California Edison Company's 2021 Electric Procurement Cost Revenue Requirement Forecast, 2021 Forecast of Greenhouse Gas-Related Costs, and Power Charge*

III. PARTICIPATION IN THE PD'S FRAMEWORK FOR PROVIDING CONFIDENTIAL DATA FOR CCA LONG-TERM PCIA FORECASTING SHOULD BE VOLUNTARY

The PD represents the Commission's diligent efforts to provide a methodology for CCAs to access confidential ERRA data on a year-round basis for long-term PCIA forecasting purposes. These efforts are certainly appreciated and CalCCA understands the delicate balancing act between protecting confidential information and the need for transparency. However, the PD's numerous requirements for such access will likely result in CCAs determining that utilizing publicly available data to develop their long term PCIA forecasting is sufficient and more cost effective. The PD's proposed framework for CCA access to year-round confidential data: (1) limits how and what reviewing representatives may present to their clients;[9] (2) limits disclosures by reviewing representatives to the CCAs to once per quarter;[10] (3) creates an on-going requirement for CCA reviewing representatives to serve *both* the Commission and the IOUs "all information that they disclose to their clients under this decision," essentially turning the CCA reviewing representative into a "Public PCIA forecaster;"[11] (4) requires CalCCA or its CCA members to organize a meeting with interested CCAs and the IOUs to discuss the proposed format and content of the PCIA forecasting analyses;[12] and (5) requires CalCCA or a member CCA to file a Tier 3 Advice Letter including detailed information regarding the information to be provided by CCA reviewing representatives, an example analysis with "dummy information," a proposed NDA, and a list of CCAs seeking the data access.[13]

Indifference Adjustment Trigger Mechanism Surcharge, A.20-07-004, A.20-10-007 (Dec. 17, 2020), at OP 8.

[9] PD at 13-14, COL 8; OP 2.

[10] *Id.* at 14-15, COL 10, OP 3.

[11] *Id.* at 14-15, COL 9, OP 3.

[12] *Id.* at 13, COL 7, OP 1.

[13] *Id.* at 13-14; COL 8, OP 2.

On balance, if the Commission does not accept CalCCA's proposed NDA approach, CCAs may be better served by developing a database of publicly available data for long-term PCIA rate forecasting, particularly given the PD's clarification on data access for short-term forecasting. Accordingly, if the Commission adopts the PD's proposed framework, it should note that participation in such a framework is voluntary and adopt the modifications set forth in Attachment A.

IV. THE COMMISSION SHOULD ADOPT THE PD'S EXCLUSION OF VOLUNTARY ALLOCATIONS FROM RPS MPB CALCULATIONS

The Commission should adopt the PD's conclusion to exclude Voluntary Allocations from calculations of the MPB. Removing Voluntary Allocation transactions from the MPB calculation will result in the MPB accurately reflecting market prices and dynamics.[14] As the Voluntary Allocation transactions will be contracted for at the applicable year's MPB, such transactions should be excluded to ensure the new calculation is not weighted by a previous year's MPB. On an ongoing basis to ensure a stable RPS MPB, the Commission should monitor the impact of the Voluntary Allocation process on the liquidity of the bi-lateral RPS market.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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California Community Choice Association

June 30, 2022

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[14] *Id.* at 18, COL 12.

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO DATA ACCESS AND VOLUNTARY ALLOCATIONS IN MARKET PRICE BENCHMARK CALCULATIONS

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

FINDINGS OF FACT

New Finding

X. Providing CCA reviewing representatives a minimum of eight months of access to confidential ERRA data will reduce future discovery disputes and keep CCA customers informed prior to the implementation of consolidated rate changes.

CONCLUSIONS OF LAW

New Conclusion

X. D.22-01-023 provides CCA reviewing representatives a minimum of eight months of access to the IOUs' confidential ERRA data.

X. Participation by CalCCA and any individual CCA in the data access process set forth in this Decision for year-round access to confidential ERRA data for the purpose of developing PCIA forecasts for CalCCA and any individual CCA is voluntary.

ORDERING PARAGRAPHS

New Ordering Paragraph

X. Participation by CalCCA and any individual CCA in the data access process set forth in this Decision for year-round access to confidential ERRA data for the purpose of developing PCIA forecasts for CalCCA and any individual CCA is voluntary.

JULY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO DATA ACCESS AND VOLUNTARY ALLOCATIONS IN MARKET PRICE BENCHMARK CALCULATIONS

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On behalf of
California Community Choice Association

July 5, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THE COMMISSION SHOULD ADOPT CALCCA'S DESCRIPTION OF THE DATA REQUIRED FOR PCIA FORECASTING IN PLACE OF THE DESCRIPTION PROVIDED BY THE JOINT UTILITIES 3

I. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES' REQUEST TO MODIFY THE MODEL NDA AS OVERLY RESTRICTIVE AND PREMATURE 4

III. CONCLUSION 5

SUMMARY OF RECOMMENDATIONS

- The Commission should reject the Joint Utilities' over-simplistic and inaccurate description of the data necessary to accurately forecast Power Charge Indifference Adjustment (PCIA) rates, and instead define such data as the true-ups recorded in Portfolio Allocation Balancing Account (PABA) and Energy Resource Recovery Account (ERRA) balancing accounts for under- or over- collections during the current year, plus projections of output and costs of the investor-owned utilities' (IOUs') PCIA-eligible resources; and

- The California Public Utilities Commission (Commission) should reject as too restrictive and premature the Joint Utilities' requested modifications to the existing Model Non-Disclosure Agreement (NDA) for the data access methodology proposed in the PD.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO DATA ACCESS AND VOLUNTARY ALLOCATIONS IN MARKET PRICE BENCHMARK CALCULATIONS

The California Community Choice Association[1] (CalCCA) submits these reply comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Resolving Phase 2 Issues Related to Data Access and Voluntary Allocations In Market Price Benchmark Calculations* (PD), dated June 10, 2022.

I. INTRODUCTION

CalCCA appreciates the Commission's attempt in the PD to balance the competing interests at play in providing access to confidential data for the preparation of accurate power charge indifference adjustment (PCIA) long-term forecasting. As stated in CalCCA's Opening

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Comments,[2] however, the PD's numerous requirements for allowing such access may outweigh the relative value of using confidential data for long-term planning purposes. Therefore, if the Commission does not adopt CalCCA's original proposal to base the methodology on the use of a Non-Disclosure Agreement (NDA), the Commission should modify the PD to make participation in the proposed framework *voluntary* for CalCCA and individual community choice aggregators (CCAs).

In Opening Comments, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (the Joint Utilities) request modifications to the PD to further define the categories of data they will provide to enable the CCAs to forecast the PCIA.[3] Clarification of the categories of data to be provided is worthwhile, but CalCCA urges the Commission to reject the Joint Utilities' oversimplistic and inaccurate description of the data necessary for accurate PCIA forecasting. Instead, the Commission should adopt CalCCA's description of the necessary data, as provided below.

The Joint Utilities also request that the PD require additional restrictions be added to the existing Energy Resource Recovery Account (ERRA) Forecast Model Nondisclosure Agreement (NDA). The Joint Utilities' recommendations for these terms are overly restrictive (including requiring a reviewing representative (RR) to sign under penalty of perjury when that RR is already subject to strict requirements under the NDA and Commission Orders). In addition, the CCAs hiring the RR are in the best position to propose an NDA, and submit it for review along with its Tier 2 Advice Letter, as set forth in the PD.

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[2] *California Community Choice Association's Comments on the Proposed Decision Resolving Phase 2 Issues Related to Data Access and Voluntary Allocations in Market Price Benchmark Calculations*, R.17-06-026 (June 30, 2022) at 4.

[3] *Opening Comments of Joint Utilities on Decision Resolving Phase 2 Issues Related to Data Access and Voluntary Allocations in Market Price Benchmark Calculation*, R.17-06-026 (June 30, 2022) (Joint Utilities' Opening Comments).

As set forth more fully below, CalCCA provides the following recommendations:

- The Commission should reject the Joint Utilities' over-simplistic and inaccurate description of the data necessary to accurately forecast PCIA rates, and instead define such data as the true-ups recorded in Portfolio Allocation Balancing Account (PABA) and ERRA balancing accounts for under- or over- collections during the current year, plus projections of output and costs of the investor-owned utilities' (IOUs') PCIA-eligible resources; and

- The Commission should reject as too restrictive and premature the Joint Utilities' requested modifications to the existing Model NDA for the data access methodology proposed in the PD.

II. THE COMMISSION SHOULD ADOPT CALCCA'S DESCRIPTION OF THE DATA REQUIRED FOR PCIA FORECASTING IN PLACE OF THE DESCRIPTION PROVIDED BY THE JOINT UTILITIES

The Joint Utilities' Opening Comments request the Commission clarify the description of data necessary for PCIA forecasting. While CalCCA agrees that such a clarification is worthwhile, the Joint Utilities' proposed description should be rejected, and the Commission should instead adopt the description provided below.

The Joint Utilities assert that the data required for PCIA forecasting must only be data "relevant" to departed load, which they describe as "only the vintaged PABA data relevant to a current departing load customer's PCIA rate."[4] They further assert that current ERRA balancing account information is not relevant "because ERRA costs are paid for by bundled service customers, not departing load customers."[5]

The Joint Utilities' description is overly simplistic and mischaracterizes the data the PD finds is necessary and in the public interest for CCAs to access. The PD specifically recognizes that there is a public interest in allowing CCAs access to ERRA forecast data when an ERRA

4 Joint Utilities' Opening Comments at 5.

5 *Id*. at 5-6.

forecast proceeding is not pending.[6] The Joint Utilities' characterization also ignores that the final ERRA balance is used in the calculation of the following year's PCIA.

An accurate description of the data necessary for PCIA rate forecasting therefore *does* include both PABA and ERRA balancing account information, as specified below:

- PCIA rate forecasts for the upcoming year rely on projections of output and costs of the IOUs' PCIA-eligible resources plus the true ups recorded in PABA and ERRA balancing accounts for under- or over-collections during the current year. Confidential details of these data are currently available within an ERRA Forecast case; and

- Long-term PCIA rate forecasts also rely on projected output and costs of the IOUs' PCIA-eligible resources, the basis for which would be the latest forecast information included in the workpapers provided in the ERRA Forecast case, adjusted for expected changes over the forecast horizon.

While the Commission should reject the Joint Utilities' request to adopt their description of the data required for PCIA forecasting, CalCCA recommends the Commission adopt its more accurate description provided above.

III. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES' REQUEST TO MODIFY THE MODEL NDA AS OVERLY RESTRICTIVE AND PREMATURE

The Joint Utilities also err in urging specific amendments to the form NDA to be used in the process. The PD correctly requests that participating CCAs propose an NDA.[7] The tasks assigned to the Reviewing Representative are numerous and complex. The CCAs who will be engaging these representatives are best placed to modify the existing ERRA Forecast NDA to conform it to this process, and then to provide the revised NDA with the Tier 2 Advice Letter.

In addition, the further restrictions the IOUs propose are severe and unnecessary, given the parties' long history with the consultancies likely to be engaged for this work. There is no basis for the IOUs' request to specify the dispute resolution methodology, or to request that

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6 PD at 8.

7 *Id.* at 20, COL 8(a).

reviewing representatives sign the NDA under penalty of perjury, when the RR is already bound by the NDA and Commission orders.[8] For the reasons set forth herein, the Joint Utilities' requested modifications to the Model NDA should be rejected.

IV. CONCLUSION

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

Respectfully submitted,

/s/ Ann Springgate
Ann Springgate
KEYES & FOX LLP

On behalf of
California Community Choice Association

July 5, 2022

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8 Joint Utilities' Opening Comments at 11-12.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON RULING OF THE ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE REQUESTING COMMENTS ON FINANCIAL SECURITY REQUIREMENTS AND REENTRY FEES, AND MODIFYING THE PROCEEDING SCHEDULE

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July 5, 2022

TABLE OF CONTENTS

I. INTRODUCTION 1

II. BACKGROUND 4

III. CALCCA PROPOSALS 5

A. Proposed Modifications to the FSR Calculation 5

1. Broaden the Energy Forward Price Data Set to Avoid Over or Underestimating Actual Energy Market Prices 6

2. Modify the FSR Calculation to Account for CAM Energy 11

3. Modify the Forecast RA Cost Components of the FSR Calculation to account for CAM and DR 12

4. Modify the Forecast RPS Cost Components of the FSR Calculation to Account for VA and any CAM RPS 13

5. Modify the Forecast Retail Revenue Component to Better Reflect the Actual Revenues the POLR Can Expect to Receive 14

6. If the Commission Adopts SCE's Proposal to Deduct the Returning Customer's Vintage PCIA from the Revenue Calculation, then the FSR Calculation Must Also Account for the PCIA Hedge Effect 16

7. Adjust the Size of Individual FSR Postings Requirements to Account for Risk 19

B. Alternative to Individual FSRs: Modified Credit Pool Mechanism 21

1. If the Commission Adopts a Liquidity Pool, it Should do so Through a Risk-Adjusted Pooled Credit Facility in Favor of the POLR to Cover Two Months of Expected Energy Costs and Secured by Six Months of Revenue from the Returning Customers 23

2. The Size of the Liquidity Pool Must Consider Probability of Drawing Upon the Pool 24

IV. RESPONSES TO FSR, RE-ENTRY FEE AND DE-REGISTRATION QUESTIONS IN THE RULING 26

A. 2.1 FSR Methodology Refinements 26

1. Incremental Procurement 26

Table of Contents
(continued)

2. Revenues 30

3. Administrative Costs...34

4. Other 36

B. 2.2 Frequency of Updates 36

C. 2.3 FSRs for ESPs and CCAs 38

D. 2.4 Accessing the FSR 38

V. CONCLUSION...39

ATTACHMENT A:
PACIFIC GAS AND ELECTRIC COMPANY 2023 GENERAL RATE CASE PHASE I APPLICATION 21-06-021 DATA RESPONSE

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

D.18-05-022 .... 35, 36, 38
D.21-05-030 13

California Public Utilities Commision Proceedings

A.18-12-009 35
R.03-10-003 35
R.18-07-003 13
R.21-03-011 .... passim

SUMMARY OF RECOMMENDATIONS

- California Community Choice Association (CalCCA) provides a proposal for individual financial security requirement (FSR) postings and a proposal for a pooled credit mechanism. These two proposals are separate and distinct, and the California Public Utilities Commission (Commission) must require either individual FSR postings or contribution to a pooled credit mechanism, not both, so as not to over-securitize the risk of customer return.

Recommendations for Modifying the FSR Calculation

- Using energy forwards from one month to calculate the forecast energy cost component of the FSR calculation can significantly over or underestimate actual energy market prices; instead, the *energy* cost component should be calculated using a three-month average of the Intercontinental Exchange (ICE) energy forwards rather than the current single month average;

- The Commission should modify the FSR calculation to account for Cost Allocation Mechanism (CAM) *energy* by reducing the volume of energy included in the calculation in proportion to the load-serving entity's (LSE's) share of the CAM portfolio to better reflect the actual costs the Provider of Last Resort (POLR) can expect to incur upon customer return;

- The Commission should modify the *resource adequacy* (RA) cost component of the FSR calculation by reducing the volume of RA included in the calculation in proportion to the LSE's share of CAM and demand response (DR) allocations to better reflect the actual costs the POLR can expect to incur upon customer return;

- The Commission should modify the *renewable portfolio standard* (RPS) cost component of the FSR calculation by reducing the volume of RPS in the calculation to account for RPS Voluntary Allocations (VA) held by the LSE to better reflect the actual costs the POLR can expect to incur upon customer return;

- The Commission should modify the *forecast retail revenue* reduction component of the FSR calculation by adjusting the calculation for rate seasonality and the LSE's customer class mix to better reflect the actual revenues the POLR can expect to receive upon customer return;

- If the Commission modifies the FSR for Power Charge Indifference Adjustment (PCIA), then the FSR calculation should consider that the returning load will not subject the investor-owned utility (IOU) to the full amount of energy and cost of the California Independent System Operator Corporation (CAISO) market due to the hedge effect of the PCIA portfolio and CAM portfolio provided to all bundled load customers including returned load; and

- The Commission should adjust FSR posting requirements to account not only for the consequences of returning customers to the POLR, but for the likelihood that a customer return may occur.

Summary of Recommendations
(continued)

Recommendations for a Modified Credit Pool Mechanism

- If, as an alternative to the FSR, the Commission establishes a liquidity pool, it should do so through a risk-adjusted pooled credit facility established by the POLR to cover two months of expected energy costs and secured by six months of revenue from the returning customers;
- The size of the liquidity pool should be adjusted to reflect the unhedged energy costs of returning customers (*i.e.*, reduced for the hedge value provided by the IOUs PCIA and CAM portfolios); and
- The size of a liquidity pool must take into account the probability of drawing upon the pool in the event of involuntary customer return.

Other Recommendations

- The FSR and Re-Entry Fee calculations do not need to be modified to adjust for waivers;
- When considering whether the current calculation of administrative costs adequately covers actual administrative costs that would be incurred upon customer return, the Commission must examine the significantly larger administrative costs of Pacific Gas and Electric Company (PG&E) relative to the other IOUs; and
- The posted FSR amount should not be updated more frequently than twice a year.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON RULING OF THE ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE REQUESTING COMMENTS ON FINANCIAL SECURITY REQUIREMENTS AND REENTRY FEES, AND MODIFYING THE PROCEEDING SCHEDULE

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying The Proceeding Schedule (Ruling), dated on May 2, 2022, and E-Mail Ruling Granting Request for an Extension of Time to File Financial Security Requirement and Reentry Fee Comments, and Further Modifying the Phase 1 Schedule (Email Ruling), dated May 24, 2022.

I. INTRODUCTION

The California Public Utilities Commission (Commission) must strike the right balance between protecting bundled customers and setting securitization requirements so high that they unreasonably reduce the load-serving entity's (LSE's) liquidity or credit capacity thereby

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

undermining stable operations, even under an extreme event. To this end, the Commission must consider modifications to the financial security requirement (FSR) calculation that address both the risks associated with customer return *and* the likelihood of customer return occurring. Modifying the FSR calculation without considering the likelihood of customer return will result in imbalanced and unnecessarily costly FSR postings.

In addition to properly accounting for risk, the Commission must modify the amount of required security to reflect the net costs of customer return more accurately. Accuracy requires a more granular consideration of the costs the provider of last resort (POLR) will experience in serving the returned customers and the incremental revenues it will receive from those customers. The May 10, 2022 Advice Letters (ALs) submitted by the three investor-owned utilities (IOUs) providing the semi-annual updates to the community choice aggregator (CCA) FSR posting amounts[2] demonstrate changes are needed to all three components of the forecast cost of serving returned customers: energy, Resource Adequacy (RA), and Renewable Portfolio Standard (RPS) costs.

The Commission can adjust for risk and achieve greater accuracy in the FSR in one of two ways: (1) adjust the FSR in the context of individual FSR postings, as is currently done, or (2) establish a pooled credit mechanism, which also provides the POLR upfront liquidity to cover immediate market costs. In these comments, CalCCA provides recommendations suited toward either approach. These two proposals are separate and distinct, and the Commission must require either individual FSR postings *or* contribution to a pooled credit mechanism, not both, so as not to over-securitize the risk of customer return. Importantly, both problems – risk adjustment and

[2] PG&E AL 6589-E-A, SCE AL 4789-E-A, and SDG&E AL 4002-E-A.

accuracy – must be considered whether the Commission pursues modifications to the individual FSR postings *or* a pooled credit mechanism.

In summary, CalCCA makes the following recommendations to adjust for risk in calculating the security required by the Provider of Last Resort (POLR).

- The Commission should adjust FSR posting requirements to account not only for the consequences of returning customers to the POLR, but for the likelihood that a customer return may occur;
- If, as an alternative to the FSR, the Commission establishes a liquidity pool, it should do so through a risk-adjusted pooled credit facility established by the POLR to cover two months of expected energy costs and secured by six months of revenue from the returning customers; and
- The size of a liquidity pool must take into account the probability of drawing upon the pool in the event of involuntary customer return.

CalCCA offers these recommendations to ensure the accuracy in the amount of security reasonably required to account for the net costs of customer return:

- Using energy forwards from one month to calculate the forecast energy cost component of the FSR calculation can significantly over or underestimate actual energy market prices; instead, the *energy* cost component should be calculated using a three-month average of the Intercontinental Exchange (ICE) energy forwards rather than the current single month average;
- The Commission should modify the FSR calculation to account for Cost Allocation Mechanism (CAM) *energy* by reducing the volume of energy included in the calculation in proportion to the LSE's share of the CAM portfolio to better reflect the actual costs the POLR can expect to incur upon customer return;
- The Commission should modify the *resource adequacy* (RA) cost component of the FSR calculation by reducing the volume of RA included in the calculation in proportion to the LSE's share of CAM and demand response (DR) allocations to better reflect the actual costs the POLR can expect to incur upon customer return;

- The Commission should modify the *renewable portfolio standard* (RPS) cost component of the FSR calculation by reducing the volume of RPS in the calculation to account for RPS Voluntary Allocations (VA) held by the LSE to better reflect the actual costs the POLR can expect to incur upon customer return;

- The Commission should modify the *forecast retail revenue* reduction component of the FSR calculation by adjusting the calculation for rate seasonality and the LSEs' customer class mix to better reflect the actual revenues the POLR can expect to receive upon customer return;

- If the Commission modifies the FSR for Power Charge Indifference Adjustment (PCIA) then the FSR calculation should consider that the returning load will not subject the IOU to the full amount of energy and cost of the California Independent System Operator Corporation (CAISO) market due to the hedge effect of the PCIA portfolio and CAM portfolio provided to all bundled load customers including returned load;

- The size of the liquidity pool should be adjusted to reflect the unhedged energy costs of returning customers (*i.e.*, reduced for the hedge value provided by the IOUs' PCIA and CAM portfolios);

- The FSR and Re-Entry Fee calculations do not need to be modified to adjust for waivers;

- When considering whether the current calculation of administrative costs adequately covers actual administrative costs that would be incurred upon customer return, the Commission must examine the significantly larger administrative costs of Pacific Gas and Electric Company (PG&E) relative to the other IOUs; and

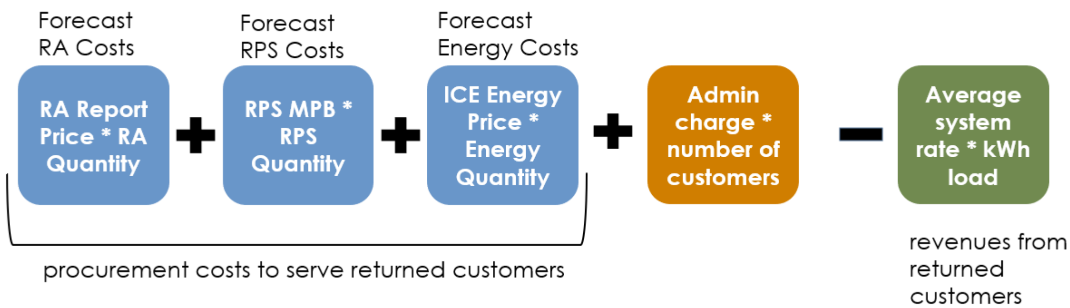
- The posted FSR amount should not be updated more frequently than twice a year.

CalCCA supports continued exploration of all of these proposals to support an FSR approach that strikes the right balance between protecting bundled customers and ensuring and avoiding unreasonably high and inaccurate security requirements.

II. BACKGROUND

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

Figure 1



CalCCA's proposals and responses to questions in the Ruling that follow touch on each of these elements and recommend critical changes that will improve the accuracy of the forecast net costs the POLR is expected to incur to serve returned customers.

III. CALCCA PROPOSALS

A. Proposed Modifications to the FSR Calculation

The FSR calculation intends to produce an FSR posting that covers six months of procurement (*i.e.*, RA, RPS, and energy) costs and administrative costs offset by revenues the POLR will receive from returned customers. As currently formulated, however, the FSR does not accurately reflect costs or revenues. The Commission should modify the FSR calculation to improve its accuracy. In doing so, the Commission must commit to adopting all reasonable changes proposed, rather than "cherry-picking" modifications to drive the FSR posting amount one direction or another. To improve the accuracy of the FSR calculation, CalCCA makes the following proposals.

1. Broaden the Energy Forward Price Data Set to Avoid Over or Underestimating Actual Energy Market Prices

The current FSR calculation includes forecast energy costs the POLR can expect to pay as a result of serving the returned customers. The energy prices used to calculate forecast energy costs come from the ICE forward price quotes from the month prior to the month the FSR calculation occurs. Using a broader data set of price quotes will improve the accuracy of energy cost component of the FSR calculation.

There is a significant amount of literature available discussing the ability of a forward market to predict future prices. William Emmons and Timothy J. Yeager stated:

> Futures prices of non-storable commodities can deviate significantly from spot prices because of anticipated changes in supply or demand.[3] [4]

Commodity forward markets are used for two purposes. First, they may hedge a buyer or seller's risk of future prices. Second, they may be used as speculative devices by entities to profit from price divergence between the forward and actual price of the commodity when the forward period arrives. This is not a model of convergence to the actual price but rather differing parties having differing estimates of the future market prices with differing tolerance to price volatility.

An analysis of forward energy price quotes from New York Mercantile Exchange (NYMEX)[5] reveal that they are not a good predictor of the actual CAISO settlement prices the POLR would pay to serve the returned customers. The potential divergence of using a forward quote

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[3] https://www.stlouisfed.org/publications/regional-economist/january-2002/the-futures-market-as-forecasting-tool-an-imperfect-crystal-ball

[4] While the energy market is developing more storage for the energy commodity, that storage is generally short-term in nature covering hours. This type of storage will arbitrage prices within a day but does not address the fundamental movers of longer-term price trends including the costs of other inputs to electricity production.

[5] While the IOUs use ICE forwards for this purpose, the ICE data is not publicly available and cannot be published for this purpose even if a subscription were obtained. NYMEX data is therefore used for demonstration purposes of the volatility of forward price quotes. CalCCA has obtained an ICE subscription and observes similar patterns to those demonstrated by the NYMEX data shown here.

to predict the future price of energy in the CAISO is highly variable. In fact, if the FSR for 2021 had been calculated using April of 2021 forward NYMEX prices, the predicted price would have been $99.38 on-peak for NP-15 in August while the actual settled value at the CAISO market was $65.57. A similar result can be seen for SP-15 where the April NYMEX quote for August was $118.85 with a CAISO settled price of $65.08. Such a calculation would have significantly over-forecasted the cost of energy and resulted in a high FSR that would have secured against a pricing event that never occurred.

The following graphs show this relationship between NYMEX forward price quotes for both NP-15/SP-15 and actual CAISO settled prices over the past year.

Figure 2

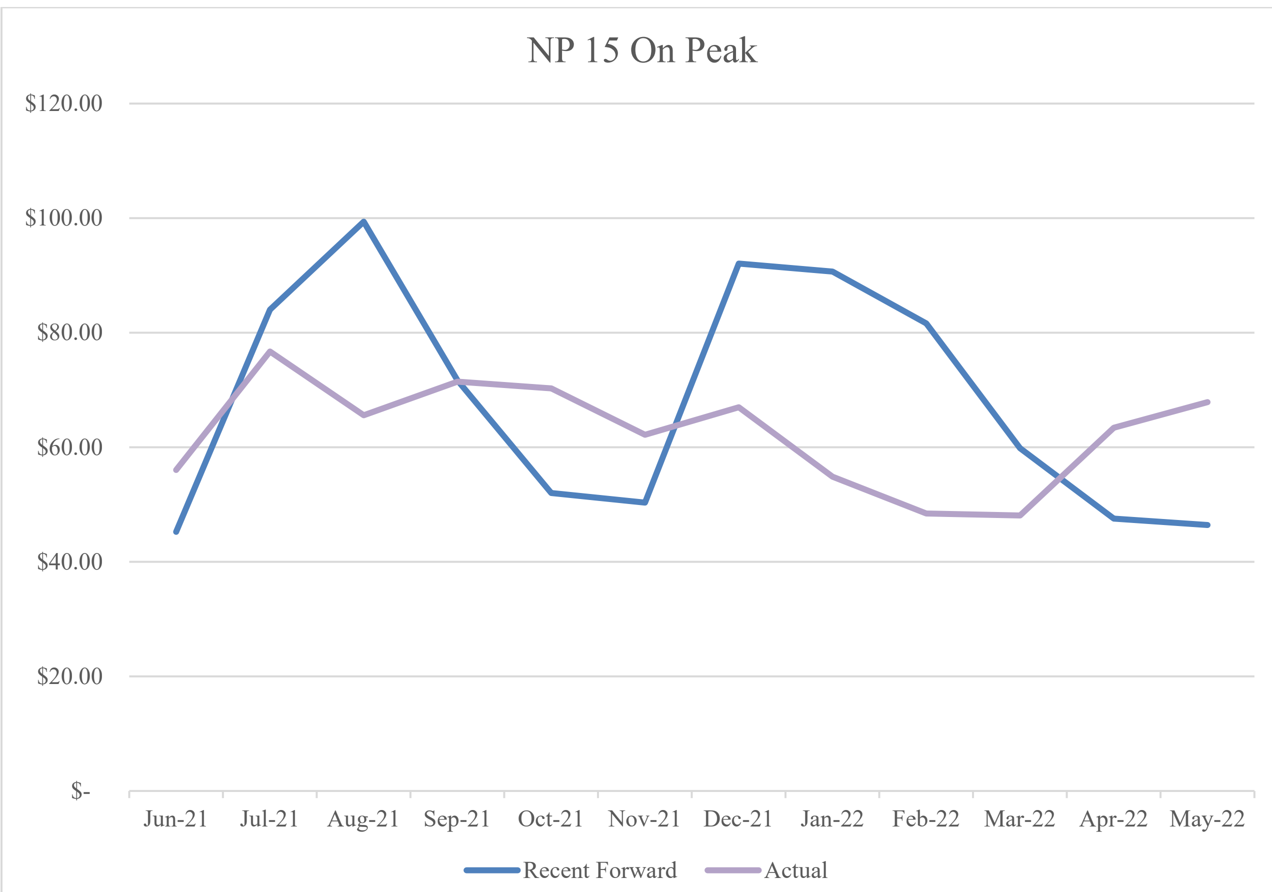
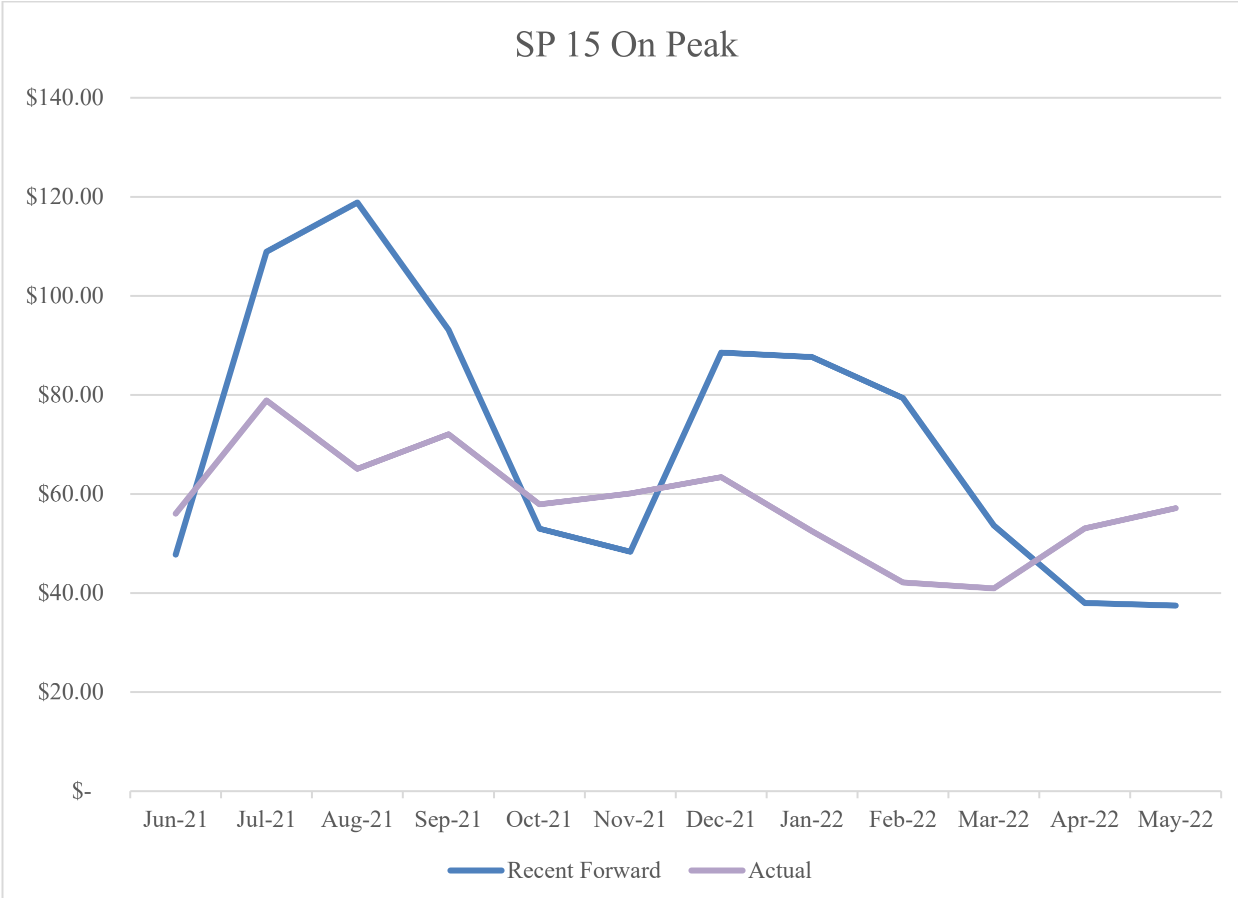


Figure 3



The FSR calculation is sensitive to the forecast energy cost component, so it is critical this piece of the calculation is as accurate as possible. This sensitivity is demonstrated by the semi-annual update submitted in Southern California Edison Company's (SCE's) AL 4789-E on May 10, 2022. In the AL, SCE indicates an increase in CCAs' FSR postings in its service territory that is largely driven by an increase in the ICE Forward Energy cost component.[6] The result is a drastic increase in the amount of financial security CCAs in SCE's territory will be required to post. High forecast energy market prices from the April quotes have increased FSRs for SCE CCAs from approximately $1.5 million to approximately $110 million for all ten CCAs. An increase of this

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

magnitude will have palpable impacts for CCAs as they approach summer, reducing liquidity and/or credit capacity. In contrast, the postings for CCAs in the PG&E and San Diego Gas & Electric (SDG&E) service territories for the same period remain at the minimum, as both PG&E and SDG&E relied on March ICE energy price quotes and have higher bundled system average rates. Requiring CCAs to over securitize the FSR postings will reduce liquidity for the CCAs and may be the cause of credit rating downgrades. Credit downgrades can lead to higher collateral posting requirements with counterparties which would further exacerbate liquidity challenges and ultimately add significant costs for the CCAs to finance their operations.

As the NYMEX data and SCE AL 4789-E demonstrate, reliance on forward quotes from one month to estimate actual energy costs can result in an FSR posting that (1) does not reflect the actual costs the POLR would incur in the event of customer return, and/or (2) creates an unacceptable level of volatility from posting to posting. For these reasons, the Commission should modify the forecast energy cost component to use a broader data set to more accurately predict the future CAISO market prices, as opposed to relying on forward price quotes from just one month and would be a better predictor of actual CAISO settled prices.

The use of a single month of forward quotes results in a small number of samples. ICE creates forward quotes for each business day of the month meaning that there are between 20 to 23 observations per month to establish the sample for this forecast of energy prices. While there is no firm rule on the minimum sample size necessary, statistically, the smaller the sample size, the more prone to error the estimate. In Figures 4 and 5, the Mean Squared Error (MSE) (*i.e.*, the average of the square of the difference between the estimate and the actual) was significantly reduced by using three months of forward data as compared to the most recent month of forward data. For NP 15 on peak, the MSE dropped from 470 to 355 and for SP 15 on peak the MSE dropped from 708 to 490 where a lower MSE indicates that the predicted values better match the actual values. The objective of the forward quote should be to accurately predict the future price and not to cause an under or over-securitization. The analysis performed by CalCCA of the NYMEX forward data demonstrates that the error (*i.e.*, the difference between the actual observation and the predicted value) is less when using the three month average than the single month accomplishing the objective of neither a bias toward under or over-securitization.

A broader sample of price quotes -- a simple average of the *most recent three months* of NYMEX forward quotes for the on-peak periods for NP and SP 15 – increases the "accuracy" of the outcome and smooths the volatility inherent in a one-month sample. Below (Figure 4 and Figure 5) are the two graphs above (Figure 2 and Figure 3) modified to reflect this outcome.

Figure 4

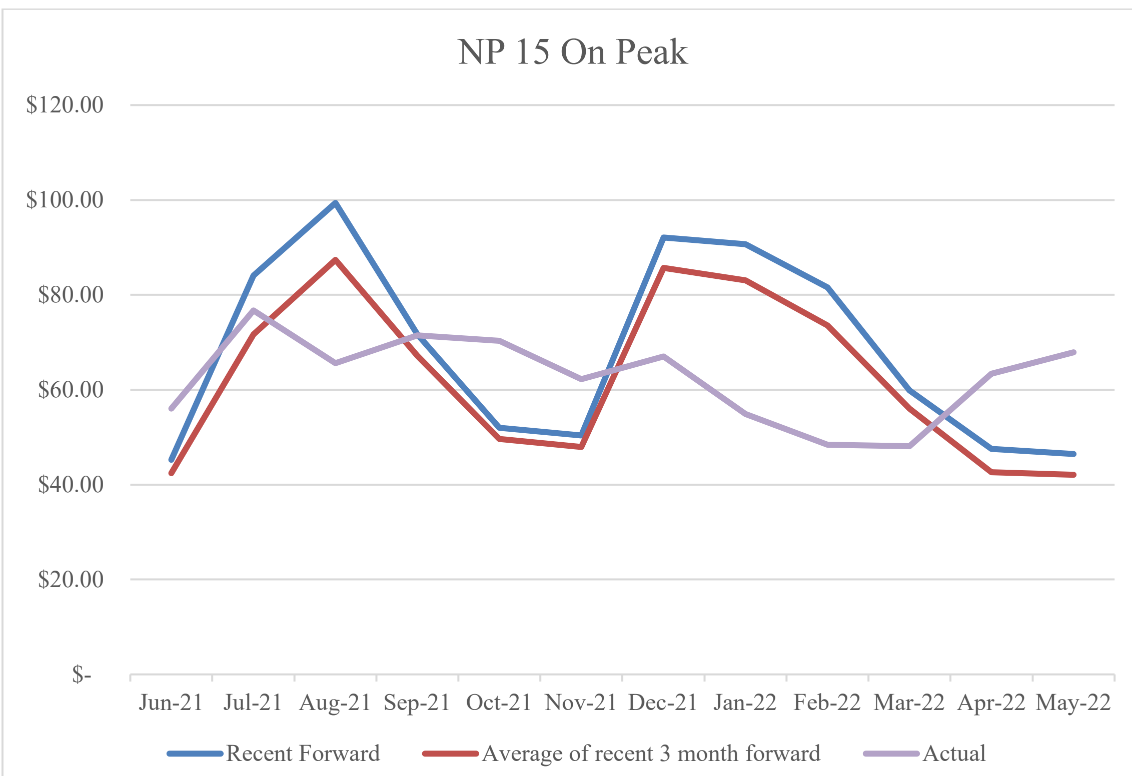
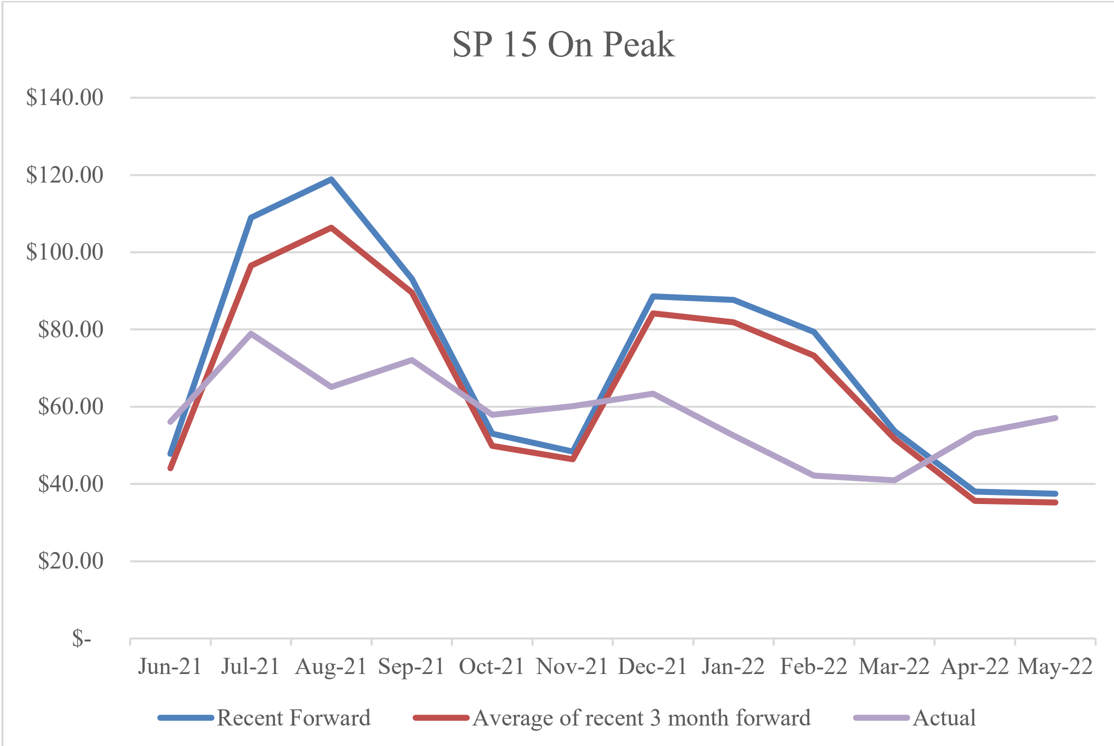


Figure 5



The Commission should modify the forecast energy cost component of the FSR calculation to use a broader set of data as a better predictor of actual costs the POLR can expect to accrue when serving the returned customers. Based upon the data studied and described above, the Commission should use a three-month average of future quotes rather than the current one-month average.

2. Modify the FSR Calculation to Account for CAM Energy

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

When a customer returns to bundled service, CAM costs and offsetting revenues follow the customer. As a result, the POLR receives an additional energy hedge value as those CAM costs and offsetting revenues follow the customer. Therefore, much like the RA capacity associated with CAM resources discussed below, the IOU will not be at risk for the cost of energy associated with the CAM portfolio used to serve the bundled load including the returned load of the returning customer load.

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

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

3. Modify the Forecast RA Cost Components of the FSR Calculation to account for CAM and DR

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

CAM and DR resources provide RA for all customers through a charge recovered in distribution rates. The RA capacity these resources will follow the customer whether that customer is served by a CCA or the IOU. Therefore, the customer will pay for and receive its proportional share of RA associated with the CAM resources upon an involuntary customer return. These costs should not be duplicated through the FSR.

To avoid duplication and accurately reflect the POLR's return costs, CAM and DR RA quantities should be netted out of the RA quantity priced by the calculation, as outlined in the example in section IV.A.1.b. The value of the CAM and DR resources follows the load and therefore will return to the IOU upon customer return, reducing the RA costs the POLR will incur. In other words, these resources will provide a portion of the RA capacity needed to serve a returning customer.

4. Modify the Forecast RPS Cost Components of the FSR Calculation to Account for VA and any CAM RPS

The POLR will have RPS available to serve returned customers from two possible sources: (1) the customer's portion of a Voluntary Allocation of RPS resources from the PCIA portfolio, and (2) the customer's portion of CAM RPS, if any.

The RPS VA process, established in the PCIA proceeding, similarly allows the output of RPS resources transferred from the IOUs to CCAs to revert back to the IOU upon an event of default.[7] The RPS costs the POLR would incur to serve the returned customers would be reduced given the IOU would again use those resources for RPS compliance on behalf of the returned customers. Therefore, in the event of an LSE bankruptcy, the primary concern within the context of POLR, the

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7 *See* D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* Rulemaking (R.) 17-06-026 (May 20, 2021) (establishing the RPS VAMO process). The first VAMOs are being conducted in 2022, and monitored in the RPS proceeding, R.18-07-003. The IOUs submitted, and Energy Division approved, pro forma Voluntary Allocation contracts with provisions governing CCA defaults (such as failure to pay or bankruptcy). *See* Resolution E-5216 (June 23, 2022) (approving the IOUs' standard VA pro forma contracts). In an event of default by a CCA that is a signatory to one of the IOU's pro forma VA contracts, the IOU can declare an early termination of the contract and suspend performance. *See, e.g.,* Section 5.2 of EEI Master Power Purchase and Sale Agreement (incorporated by PG&E Pro Forma Master Power Purchase and Sale Agreement - Renewables Portfolio Standard Energy Allocation Confirmation Letter, SDG&E Confirmation for Allocation of Bundled Energy and Renewable Energy Credits, and SDG&E Confirmation for Unbundled Energy and Renewable Energy Credits); Section 5.2(a) of SCE Pro Forma Voluntary Allocation Agreement.

IOU would suspend VA deliveries pursuant to the applicable VA contract and the resources would be available to the IOU.[8] This reversion of RPS compliance value to the IOU should be reflected in the FSR calculation as a reduction in the forecast RPS cost, outlined in the example in section IV.A.1.b. While the RPS value of VA resources logically follows the returning customers to the POLR within the context of the IOU as POLR, this would need to be reevaluated in the context of a non-IOU POLR.

The RPS portion of the FSR calculation also must reflect the share of RPS resources, if any, in the CAM portfolio. CalCCA acknowledges that the vast majority of CAM resources are not RPS eligible resources. To the extent they are, however, or if future CAM procures significant amounts of RPS eligible resources, this same issue will cause an over-estimate of the FSR. The FSR thus should be reduced by these amounts.

5. Modify the Forecast Retail Revenue Component to Better Reflect the Actual Revenues the POLR Can Expect to Receive

Currently the forecast retail revenue component of the FSR calculation is calculated by multiplying the POLR's system average bundled generation rate by the returning LSE's load forecast. This overly simplified approach has the potential to misrepresent the characteristics of returning customers and the expected rates the POLR can expect to receive depending on the time of return. To improve the accuracy of the FSR calculation, the Commission should make the modifications outlined here, and expanded upon in CalCCA's responses to questions in the Ruling in section IV.A, to better reflect actual revenues the POLR can expect to receive upon customer return.

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

a. Average customer rates by class for each CCA

Calculating expected revenues using the IOU's system average rates, as is done for the FSR calculation today, may over or underestimate the actual revenues the IOU will receive from returning customers. This is because system average bundled rates that reflect the IOU's mix of customer classes will almost certainly not reflect the same mix of returning customers. Therefore, the Commission should reflect average customer rates by class for each CCA in the forecast revenue component of the FSR calculation to better reflect anticipated revenues for any individual CCA return.

b. Seasonal changes in generation rates

Currently the forecast revenue component of the FSR calculation uses an annual average generation rate, rather than reflecting the seasonality that exists within the IOU generation rates. This creates a seasonal misalignment: while the forecast energy cost component of the calculation will reflect the seasonal differences through ICE forward price quotes, the revenue component does not. Accounting for seasonality on the cost side but not the revenue side will result in an FSR/re-entry fee calculation that is artificially high in the summer and artificially low in the winter. Therefore, CalCCA recommends the Commission seasonally differentiate average generation rate revenues to match the seasonal differentiation of forecast energy costs.

c. Future rate changes that have been approved by the Commission

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

6. If the Commission Adopts SCE's Proposal to Deduct the Returning Customer's Vintage PCIA from the Revenue Calculation, then the FSR Calculation Must Also Account for the PCIA Hedge Effect

The FSR calculation inherently assumes that bundled rates may be too low to cover the costs associated with customers returning to IOU service. The FSR amount covers any under-collection that would be incurred procuring for those customers if they return to IOU service.

SCE proposes to reduce the PCIA component of the FSR revenue offset. SCE would remove the current credit against FSR obligations for PCIA revenues:

"To properly compare the future incremental costs of the energy/RPS/RA needed to serve the mass involuntarily returning load against incremental revenues for these three procurement items, the PCIA cost responsibility must be removed from the calculus. Failure to do so results in a material cost shift to bundled service customers."[9]

SCE theorizes that:

> "The current FSR and Re-Entry Fee mechanisms do not appropriately account for the PCIA cost responsibility of CCA and DA customers. This is because the FSR and Re-Entry Fee mechanisms do not distinguish between gross revenues and incremental revenues in calculating the incremental costs incurred by the IOU in a mass involuntary return, for an "apples to apples" calculation."[10]

For example, if the 2022 (bundled) vintage PCIA is 2¢ and the returned customer's 2018 vintage PCIA was 1.5¢, SCE would count only the incremental .5¢ it will receive from the returned customer through PCIA revenues.

SCE's proposed PCIA adjustment cannot be viewed or adopted in isolation. SCE fails to account for the fact that in a price spike scenario, *when bundled rates are too low, the PCIA is too high*. As a result, while the IOU is paying more to procure for returned customers than bundled rates

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9 *Opening Comments of Southern California Edison Company (U 338-E) On the Administrative Law Judge's Ruling Distributing Workshop Agenda And Providing Questions For Additional Post Workshop Comments*, R.21-03-011 (March 28, 2022) at 13.

10 *Id* at 11.

cover, the IOU is also taking in more cash from its PCIA portfolio than it needs to cover the stranded costs because PCIA rates are too high. In effect, the PCIA operates as an energy price "hedge" that must be accounted for in the FSR calculation, as explained below.

PCIA is a hedge against rising prices. PCIA reduces price exposure in all price-spike scenarios, including those in which departed customers return to IOU service. In addressing the intersection of the PCIA and FSR, the Commission must reflect this "hedge" effect.

The intuition that the PCIA reduces the IOU risk that the FSR must cover is simple, and implementing that intuition is also conceptually straightforward. The calculation can *either:*

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

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

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

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

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

The PCIA is a very complex ratemaking mechanism. A simple tweak to one element of its impact on the FSR requirement, however, creates an imbalance in accounting for the PCIA. If the Commission adopts SCE's proposed change, it must also adopt the adjustment recommended by CalCCA.

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

Risk is commonly expressed as the probability of a failure event occurring multiplied by the consequences of failure. The current FSR calculation as framed within this proceeding considers only the consequences of failure and does not account for the probability of failure. The current calculation covers 100 percent of the incremental cost of procurement minus the expected revenues of the returning customers to set the FSR amount. This results in a CCA securitizing the full expected costs of a customer return in advance, even if the probability of that return is slim. Similarly, within this proceeding, the problem statement introduced by Energy Division frames the discussion by assuming a large customer return to the POLR is inevitable, then explores how to securitize on that basis.[11] Framing the discussion in this way omits an important factor: the risk of large-scale customer returns is very small.[12]

It is important to incorporate risk-weighting into the FSR calculation to avoid over-securitization that takes up LSEs' liquidity and credit capacity that could be better used in other ways. As described in previous comments, the current posting mechanisms, including a letter of credit (LOC), cash, or a surety bond, each have cost and liquidity or credit consequences for the

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

[12] See section III.B for calculation of aggregate risk of LSE default.

CCA and its customers.[13] Excessively high FSRs take up liquidity or credit capacity that could be used to purchase hedges to mitigate price risk during high priced summers or procure clean energy resources to meet state policy and promote reliability by building the resource stack. The Commission should not continue to ignore the probability of involuntary customer return, as the result is increased costs to customers for an event that is unlikely to occur.

One way to incorporate risk adjustments for individual FSR postings is to provide an LSE an unsecured credit limit based on its credit rating and other financial metrics that inform an entity's risk of default. Incorporating risk adjustments into financial security requirements through the use of unsecured credit lines is a well-established practice. The Commission should examine existing practices in place in the industry when establishing a methodology for risk adjusting individual FSR postings.

The CAISO and the IOUs all have mechanisms to provide for unsecured credit that are condition dependent. To participate in the CAISO wholesale energy market, market participants must secure their financial transactions by maintaining an unsecured credit limit and/or by posting collateral. LSEs, including the IOUs and CCAs, also negotiate unsecured credit limits based on credit ratings for energy contracts. Paragraph 10 of the Edison Electric Institute (EEI) Collateral Annex is a standard form for use with EEI Master Power Purchase and Sale Agreements for counterparties to identify collateral thresholds based on credit ratings.[14] For example, pro-forma credit and collateral annex documents from PG&E and SCE reveal that unsecured credit is a feature of their contracting process. Where the amounts of unsecured credit for the IOU and the counterparty

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

[14] Paragraph 10 to the Collateral Annex, EEI, available at https://www.eei.org/-/media/Project/EEI/Documents/Resources-and-Media/Master-Contract/collateral_paragraph.doc?la=en&hash=7D2546F175079B14CDFA398676C84A27D3C1336D.

are left to be negotiated, SCE offers an unsecured credit table that would afford SCE unsecured credit of $50,000,000 given their current credit ratings by S&P and Moody's.[15] Similarly, PG&E and SCE Rule 23.Vand SDG&E Rule 27.V reveal that, for elements that the IOU may direct bill the CCA, the CCA may be required to apply for credit with the IOU or post collateral. Based upon this, the IOUs have contemplated a form of unsecured credit for CCAs. Another approach to incorporating risk could rely on factors estimating an LSE's risk of default depending upon credit ratings. This approach is discussed in further detail in Section III.B.2, referencing S&P's *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study.*[16] Under this approach, an LSE's total exposure would be discounted based on the likelihood of its failure.

It is a universally accepted principle in energy markets that collateral requirements should be considered in light of risk factors. The risk that a market participant is unable to make payments to a counterparty is a function of the probability that the participant will experience financial hardship. The Commission should explore appropriate unsecured collateral thresholds or other methodologies that will account for default risk when establishing financial security requirements.

B. Alternative to Individual FSRs: Modified Credit Pool Mechanism

PG&E has proposed a "procurement pool" as a potential alternative to posting of individual financial security instruments.[17] PG&E's thoughtful approach puts forth a new way of securitizing

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15 http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/SD/EEI_Paragraph_10_Collateral_Annex_20151116.docx and https://www.sce.com/sites/default/files/inline-files/EEI_Paragraph10totheCollateralAnnex.docx.

16 *See infra* at 25-26.

17 *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 29, 2022) at 14.

customer return to the POLR that would leverage the contribution of multiple LSEs into a credit pool to provide the POLR access to liquidity in the event of customer return. The value in a pool to CCAs occurs, however, *only if* the pool operates like insurance, reducing the amount of security that would be required from each CCA under the individual FSR proposal.

The major flaw of PG&E's pool proposal, however, is its calculation of the dollar amount LSEs would be required to put in to fund the pool. PG&E proposes each CCA fund the pool equal to their estimated costs during the two highest energy load months, resulting in a total pool of $1 billion across the three IOUs.[18] A pool of this magnitude is vastly oversized relative to any reasonable estimation of risk.

PG&E's approach would entirely omit generation revenues from the calculation and fail to account for the diversity benefits of pooling credit from multiple LSEs with different credit profiles and the low risk of customers returning in the first place. PG&E's rationale behind the size of its proposed pool is that it needs liquidity to fund borrowing costs for immediate CAISO energy costs for the returning customers. This does not necessitate an oversized procurement pool that does not account for expected revenues or the risk of customers returning in the first place, especially considering PG&E has not justified the notion that it will not be able to borrow to pay for CAISO energy costs in the event of customer return.

CalCCA is willing to consider an alternative to PG&E's pool proposal if (1) the pool were more appropriately sized to a reasonable level of risk *and* (2) the pool results in a lower cost and lower impacts on the CCA's liquidity and credit capacity. To this end, CalCCA proposes a modified credit pool mechanism below that differs from PG&E's pool proposal in its these two respects. In

[18] This estimate was developed by CalCCA based upon an average of 2 months energy costs for the June through November FSR consistent with the PG&E proposed methodology with updates for more recent forward price quotes and applied to all CCAs rather than just those in the PG&E area.

summary, CalCCA proposes that CCAs fund the non-utilization costs associated with a credit facility in favor of the POLR, obtained through the coordinated efforts of the POLRs and the CCAs. The security amount would be calculated as the forecast energy costs adjusted for risk, as outlined below in section III.B.2. Using current ICE data produces a total security amount of $23.61 million for the three IOUs.[19] As PG&E proposed, any interest incurred in the event of a return, would be recovered from returned customers.[20]

1. If the Commission Adopts a Liquidity Pool, it Should do so Through a Risk-Adjusted Pooled Credit Facility in Favor of the POLR to Cover Two Months of Expected Energy Costs and Secured by Six Months of Revenue from the Returning Customers

CalCCA proposes a risk-adjusted pooled credit facility in which the POLR is the beneficiary and CCAs collectively pay the non-utilization fees. Because CCAs would be responsible for these fees, terms and conditions of the credit facility would be negotiated in coordination with the POLR CCA Chief Financial Officers or other CCA financial representatives to ensure negotiation of reasonable outcome. The POLR would draw upon the facility only in the event of involuntary customer return, and the POLR would allocate non-utilization costs of the credit facility among LSEs in the pool. The credit facility would be secured by six months of revenue from the returning customers, possibly supported by a Commission financing order. Importantly, the credit facility would be adjusted relative to the *aggregate risk of LSE default* recognizing the diversity benefits of the risk pooling among LSEs and the fact that the probability of LSE default is low. This approach would result in the following steps:

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[19] This calculation uses the three-month average of the April ICE data to determine the expected two months of energy costs. This calculation is absent any hedge value from CAM or PCIA.

[20] *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 29, 2022), at 11-12.

STEP 1: Determine the size of the pool needed to support the risk, considering likelihood and consequences, as described in section III.B.2.

STEP 2: POLR establishes a credit facility for the determined amount with the ability to draw up to the limit whenever an involuntary customer return occurs. The LSEs in the pool would manage, or at minimum be directly involved in, the solicitation of the LOC to ensure negotiation of reasonable contract terms and price.

STEP 3: POLR allocates non-utilization costs of the credit facility among LSEs scaled to customer load.

STEP 4: The POLR places revenues received from involuntarily returned customers for the first six months of service into a lockbox. The revenues are used first to pay back the draw from the line of credit. Excess revenues are retained by POLR.

STEP 5: If customer revenues for the first six months do not adequately cover costs and enable full repayment of the credit facility, the POLR pays off the credit facility and recovers the shortfall through balancing account treatment with commercial paper interest from the returned customers over time.

2. The Size of the Liquidity Pool Must Consider Probability of Drawing Upon the Pool

As described in section III.A.6, this proceeding must make the shift to incorporate risk-weighting when determining the amount of financial security needed to support POLR service. In the context of a liquidity pool, the amount of the credit facility should be determined by adding the sum of the individual FSR calculations and discounting them to reflect the pooling benefits and the likelihood of having to draw from the pool.

The likelihood of having to draw from the pool is best represented by the aggregate risk of LSE default. To calculate the aggregate risk of a CCA default, CalCCA applied the global corporate average cumulative default rates published by S&P Global (S&P) in its *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study* to its member CCAs.[21] [22] There are currently seven CalCCA member CCAs that have an investment-grade credit-rating and 16 that have not been evaluated. Over one year, the default rate for investment-grade entities is 0.09 percent and the default rate for speculative-grade entities is 3.71 percent. Assuming seven CCAs at .09 percent and 16 CCAs at 3.71 percent, the average risk of a CCA failing is 2.61 percent. The S&P projections are higher than the actual CCA deregistration rate on a load-weighted basis. Since the inception of CCAs, two CCAs have deregistered. This load from deregistrations amount to a 1.05 percent deregistration rate on a load-weighted basis.

The Commission should similarly apply a measure of risk when considering how much LSEs must contribute to a liquidity pool. This can be done by first calculating the forecast CAISO energy costs for 2 months for LSEs in the pool, as PG&E proposed,[23] then multiplying the resulting dollar amount by the percent probability of default. The calculation of forecast energy costs should be adjusted to reflect the modifications proposed in section III.A, specifically, using a three-month average of the most recent forwards and including only the unhedged energy costs of returning customers (*i.e.*, reducing the size of the pool for the hedge value provided by the IOUs PCIA and

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21 *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study*, at Table 26: https://www.spglobal.com/ratings/en/research/articles/210407-default-transition-and-recovery-2020-annual-global-corporate-default-and-rating-transition-study-11900573.

22 S&P also provides a *Default, Transition, and Recovery: 2020 Annual U.S. Public Finance Default and Rating Transition Study* as well that would predict an even lower default rate at 0.03%. See Table 13: https://www.spglobal.com/ratings/en/research/articles/210709-default-transition-and-recovery-2020-annual-u-s-public-finance-default-and-rating-transition-study-12024058. CalCCA does not suggest using this default rate here as it is not consistent with the experience of CCA deregistrations in California at this point in time.

23 *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 29, 2022), at 9.

CAM portfolios). Using the probabilities from the *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study,* the FSR would be calculated as follows:

> *Forecast CAISO energy cost for 2 months for investment grade credit rated CCAs * .0009 (average default rates for investment grade entities over one year)*
> *+*
> *Forecast CAISO energy cost for 2 months of all other CCAs * .0371 (average cumulative default rate for "speculative" grade over one year)*

If the Commission adopts a liquidity pool, this calculation should be used to determine the size of the pool, as it reflects the pooling benefits and the likelihood of having to draw from the pool. As highlighted above, a pooling mechanism should be adopted only if it yields both liquidity benefits for the POLR *and* a reduced burden on LSEs. The relative merits of individual FSRs and pool mechanisms should be evaluated through the workshop process.

IV. RESPONSES TO FSR, RE-ENTRY FEE AND DE-REGISTRATION QUESTIONS IN THE RULING

A. 2.1 FSR Methodology Refinements

1. Incremental Procurement

a. There appears to be consensus among parties that the FSR calculation should use the most up-to-date Power Charge Indifference Adjustment (PCIA) market price benchmark in valuing the Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) components. Does any party object to this change? If so, why?

CalCCA does not object to updating the RPS and RA components of the calculation to use the most up-to-date PCIA market price benchmarks (MPBs). The MPBs are readily accepted as a proxy in setting the PCIA and should be equally accurate as a component of the FSR calculation.

b. Should the FSR calculation account for Voluntary Allocation and Market Offer (VAMO) resources, Cost Allocation Mechanism (CAM) resources, and/or Demand Response (DR) related RA allocations? If so, please describe how these adjustments should be reflected in the FSR/reentry fee calculation, being as specific and detailed as possible, and using examples where relevant.

Yes, as described in section III.A.3, the FSR calculation must account for the VA of the VAMO resources in the RPS cost forecast and the CAM resources and DR-related RA allocations in RA cost forecast. The value of the CAM and DR resources follows the load and therefore will transfer back to the IOU upon customer return. The RPS resources voluntarily allocated contain a termination provision in the contract between the LSE and the IOU upon an event of default, returning the RPS value of the allocated resources to the IOU as POLR. Therefore, CAM, DR, and RPS VAs will each reduce the amount of new procurement the IOU needs to undertake to serve the returned customers.

As an example of how CAM adjustments should be made in the FSR, consider an illustrative CCA with a local RA requirement of 100 megawatts (MW), a net system RA requirement of 50 MW, and a local and system CAM allocation of 10 MW. Consider a local RA price of $4.84 per kilowatt-month and a system RA price of $4.40 per kilowatt-month.

Current RA Cost Forecast Calculation

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

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

With values:

RA Cost Forecast = [(100 MW x $4.84/kw-mo) + (50 MW x $4.40/kw-mo)] x 6 x 1000 = $4,224,000

RA Cost Forecast Calculation with CAM Adjustment

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

> *RA Cost Forecast = [((CCA's Local RA Requirement (MW) –* ***<u>CCA's Local CAM allocations (MW))</u>*** *x Local RA Price ($kW-mo)) + ((CCA's Net System RA Requirement (MW)* ***<u>- CCA's System CAM allocations (MW))</u>*** *x System RA Price ($/kw-mo))] x 6 x 1000.*[24]

With values:

> *RA Cost Forecast = [((100 – 10) MW x $4.84/kw-mo)) + ((50-10) MW x $4.40/kw-mo))] x 6 x 1000 = $3,669,600*

RA Cost Forecast Calculation with CAM Adjustment and DR Adjustment

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

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

With values:

RA Cost Forecast = [((100 – 10 - 5) MW x $4.84/kw-mo)) + ((50-10 - 5) MW x $4.40/kw-mo))] x 6 x 1000 = $3,392,400

Current RPS Cost Forecast Calculation

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

[24] It should be noted that for 2023 and beyond for the SCE and PG&E areas, all local will be procured by the Central Procurement Entity. For any FSR calculation that includes the period beginning January 2023, SCE and PG&E should only include system RA within their RA Cost Forecast. This formula is still applicable to the SDG&E area.

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

RPS Cost Forecast Calculation with VA Adjustment

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

RPS Cost Forecast = [REC Value ($/MWh) x (Annual RPS Target (%) x (CCA Annual Usage Forecast (MWh)) ***– Voluntary Allocation (MWh))****] x IOU-Specific Line Loss Facto*r

c. In comments, several parties recommend limited RA, RPS, and/or Integrated Resource Plan (IRP) waivers be provided as part of POLR service. To the extent one or more of these waivers are applied, should the application of these waivers be reflected in the FSR procurement/reentry fee calculation? If so, how? Please be as specific and detailed as possible.

CalCCA supports limited waivers or deferrals of RA, RPS, and Integrated Resource Plan (IRP) compliance obligations. POLR's most critical role is to provide energy for returning customers during the six months that returning customers are under POLR service. To that end, in previous comments CalCCA outlined the following process for ensuring procurement and compliance obligations are maintained upon customer return.[25] This process recognizes that the POLR would assume the RA, RPS, and IRP obligations upon the date of customer return but that actual compliance with the obligations may be delayed depending upon market conditions and compliance timelines relative to the date of customer return. Waivers or temporary deferrals should be provided to the POLR as follows:

- RA: The existing right to an RA waiver should be maintained in the event the T-45 showings date has passed or in the event resources are unavailable at a reasonable price.

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[25] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 28, 2022) (CalCCA Comments), at 12.

- RPS: The POLR should receive a temporary deferral of RPS obligations, rather than a complete waiver of the RPS obligations, in the event customer return occurs close to an upcoming compliance deadline.
- IRP: The POLR should receive a deferral of its IRP obligation to the extent the Commission deems reasonable considering market conditions.

Depending on the formulation of the security instrument,[26] waivers may not need to be considered in the FSR and Re-Entry Fee calculation, given the uncertainty around whether waivers will be granted and the length of time over which the waiver will be granted at the time of the calculation. Since there is uncertainty of a waiver in the FSR, it is reasonable to calculate the FSR as though there will be no waiver. Upon the calculation of the Re-Entry Fee, where more is known about what RA, RPS, and IRP products the POLR will need to buy, the amount of RA, RPS, and IRP can be adjusted at that time.

2. Revenues

d. If the POLR is already receiving revenue from departed customers through the PCIA charge prior to mass involuntary migration, should the calculation of incremental generation revenues received by the POLR incorporate these existing PCIA obligations? Why or why not? If so, please describe how the existing FSR calculation should be modified, being as specific and detailed as possible.

As described in section III.A.5, the PCIA is a complex instrument that has many interactions with bundled rates and Energy Resource Recovery Account (ERRA) true-ups. While SCE has proposed to reduce the PCIA component of the FSR revenue offset by removing the current credit against FSR obligations for PCIA revenues, this proposal does not capture the full impacts the PCIA has on the FSR calculation. What SCE's proposal ignores is the fact that that the PCIA reduces IOU

[26] These comments assume the current structure of the FSR calculation that includes RA, RPS, and administrative costs. When assuming a pooled credit facility calculated on forecast CAISO energy costs only, consideration of waivers in the amount of the pool are not relevant.

risk that the FSR must cover by reducing price exposure in all price-spike scenarios, including those in which departed customers return to IOU service, effectively providing a hedge.

The accuracy of incorporating PCIA in the FSR is highly dependent on the ability of the true-ups to account for all such changes timely and accurately. The PCIA mechanism is simply too complex to assure that costs are not shifted between bundled and unbundled customers in this case. For these reasons, the Commission should not adopt a change to the revenue component of the FSR calculation such that it only reflects incremental revenues net of the PCIA component. If the Commission does adopt this change, however, it must also adopt the changes outlined in section III.A.5 above to ensure a balanced FSR calculation that reflects the "hedge" effect of the PCIA portfolio when load returns to the IOU by either:

- Adjusting the FSR cost to incorporate PCIA hedge *value*; or,
- Reducing the energy volumes used in the FSR calculation to *remove amounts* hedged through the PCIA portfolio.

e. Should the FSR calculation include one or more of the following modifications intended to further improve the accuracy of forecast generation rate revenue? For each modification, please indicate why or why not; the source of the updated data; as well as how, specifically, the changes would be incorporated into the revenue component of the FSR calculation.

As explained in section III.A.4, the Commission should adopt each of the following modifications intended to improve the accuracy of the forecast generation rate revenue. These changes would improve the revenue portion of the calculation by better reflecting actual revenues the IOU would expect to receive from the returning customers.

(i) Average customer rates by class for each CCA

Customer rates vary by class, with small residential customers experiencing the highest rates and large industrial customers experiencing relatively lower rates. The FSR calculation today uses system average rates to calculate the revenues the POLR will receive to offset the FSR costs. The IOU's mix of customer classes, however, will most likely not reflect the mix of customers returning to the IOU from a CCA. In many if not most cases, the customer mix for a CCA will be more heavily weighted toward residential rates, which yields a relatively *higher* revenue offset than is reflected in today's FSR calculation.

The Commission should correct this distortion, by calculating the FSR revenue offset using each CCA's customer mix. Rate classes are generally segmented into four high level categories: residential > commercial and industrial > agricultural > street lighting. To incorporate these rate classes in the calculation, the Commission should require forecast revenues to be calculated by multiplying the class-specific rate by the load forecast of the customers in that rate class as follows:

Forecast Revenues

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*(Residential Rate*Residential Customer Load Forecast) + (Commercial and Industrial Rate* Commercial and Industrial Customer Load Forecast) + (Agricultural Rate*Agricultural Customer Load Forecast) + (Street Lighting Rate*Street Lighting Load Forecast)*

SCE's recent AL 4789-E highlights the importance of this adjustment. Applying an estimated CCA, rather than IOU, customer mix to SCE's FSR calculation would have reduced the overall posting required from $110 million to $68 million – a reduction of 38 percent.

(ii) Seasonal changes in generation rates

"Seasonality" is reflected in the most significant component of the FSR calculation – energy costs – by updating prices each season to correspond to the period covered by the FSR. Energy costs will be higher in summer and lower in winter. This same seasonality exists within the IOU generation rates, with higher rates in summer periods and lower prices in the winter periods. And like energy costs, rate seasonality has a significant influence on the outcome of the FSR calculation.

Applying estimated seasonal rates, rather than system average rates, to the recent SCE FSR calculation would have reduced the overall posting required from approximately $110 million to $88 million – a reduction of 20 percent.

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

(iii) Future rate changes that have been approved by the Commission

If the Commission has *approved* new rates that will be in place during the time period of the FSR posting, these new rates should be applied to the applicable periods opposed to the rates from the most recent rate change. Both semi-annual updates should consider future rate changes such that the actual rates that will be in place during the six months of the FSR posting are accounted for in the calculation. This will ensure the FSR accounts for the most likely rates the returned customers will be paying based on the most current information available.

f. To account for potential timing differences between a mass involuntary return and the POLR receiving generation revenues from those returned customers, should some amount of generation revenue be backed out of the FSR calculation? Why or why not? If revenues should be backed out, what timeframe/method should be used? Please be as specific and as detailed as possible.

No, generation revenues should not be backed out of the FSR calculation. These are revenues the IOUs can expect to receive while serving the returned customers as the POLR to cover the energy, RA, and RPS procurement costs of serving those customers. Removing any portion of generation revenues would overstate the amount of costs that would not be offset by revenues, resulting in a wholly imbalanced FSR calculation and exposing CCAs and their customers to unnecessary securitization costs.

As described in section III.B, PG&E's proposal to entirely omit generation revenues from the calculation to fund its proposed procurement pool overstates the necessary size of the pool by not accounting for the benefits of pooling credit from multiple LSEs and by not accounting for the risk of customers returning in the first place. Any type of pool considered in this proceeding that omits generation revenues to provide the POLR with additional liquidity must more accurately estimate the liquidity costs that PG&E is concerned with including incorporate risk weighting to account for the probability of customer return to the POLR.

3. Administrative Costs

g. Does the current calculation of administrative costs adequately cover actual administrative costs that would be incurred in the event of a mass involuntary customer return? If not, what other costs need to be considered?

When considering whether the current calculation of administrative costs adequately covers actual administrative costs that would be incurred upon customer return, the significantly larger administrative costs of PG&E relative to the other IOUs must be reexamined. SCE and SDG&E's

administrative costs are roughly $0.50 per customer service account, while PG&E's administrative costs are $4.24 per customer service account. This issue was previously raised in R.03-10-003. The resulting D.18-05-022, declined to examine this difference. Instead, D.18-05-022 directed the utilities to identify the administrative fee as a separate item in their next GRCs, describing its components, how it is calculated, and a comparison of its fee with that of the other major California utilities.[27] While PG&E's GRC[28] and Advice Letter 5359-E provides an generic accounting of how the cost is estimated, the comparison with other major California utilities has not been offered. Indeed, while PG&E's documentation in the GRC and Advice Letter offered categories of costs and an estimated four minutes per account processing time, in response to a Joint CCA data request,[29] PG&E indicated that they have no work papers to describe how they arrived at the processing time which is the driver of the cost.

Administrative fees can be significantly reduced through automation. On May 9, 2022, SDG&E submitted AL 4000-E lowering its administrative fee from $1.12 to $0.56. SDG&E's AL explains that the administrative costs decreased because previously included manual labor has been automated, eliminated, or reduced and that previous system costs have been eliminated such that $0.55 of the $0.56 administrative fee is made up of postage, stationary, and handling costs.[30] This AL suggests that SCE and SDG&E have automated their processes, while PG&E has not. When considering how the calculation of administrative costs cover actual administrative costs, an evaluation of how the administrative costs in PG&E's territory can be reduced must be considered.

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27 D.18-05-022 at 5.

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

29 See Attachment A.

30 *Update to Schedule CCA to Decrease the Administrative Fee Pursuant to Decision 18-05-022* (AL 4000-E), May 9, 2022, at 3.

Alternatively, the Commission could recognize that PG&E's administrative costs are an outlier and use an average of SCE and SDG&E's administrative costs as the value used in the FSR calculation.

h. **Do the current minimum FSR amounts (i.e., $147,000 per CCA, and a per-customer administrative fee for residential and small commercial Direct Access customers) accurately reflect the actual administrative costs associated with a mass involuntary return of customers? If not, how should the FSR minimum amounts for CCAs and ESPs be calculated?**

i. **In your response, please consider potential differences in the scale and attributes of returning customers; whether or not the net system RA calculation should have a floor of zero megawatts; and whether administrative costs should be calculated in the same manner for CCAs and ESPs.**

CalCCA continues to consider the right approach for reflecting administrative costs, which will depend on the mechanism ultimately adopted (either a pool or individual FSR postings).

4. Other

a. **Are any other modifications necessary to ensure the FSR and reentry fees accurately reflect the cost of returning customers to be served by the POLR?**

CalCCA does not have any comments on this question at this time.

B. 2.2 Frequency of Updates

a. **Please comment on whether the posted FSR amount should be updated more frequently than twice per year (such as monthly or quarterly) to account for market volatility and changes in energy prices, and if so, whether any corresponding changes should be made to the 10% deadband approved in D.18-05-022.**

No, the posted FSR amount should not be updated more frequently than twice a year. Updating the FSR more frequently, such as quarterly or monthly would increase the volatility in the amount of FSR CCAs have to post. Updating the FSR monthly using forward price quotes from each month guarantees that in some months, CCAs will be securitizing based on forwards that are the furthest away from what the actual prices will be. Updating the FSR amount every 6 months strikes the right balance by avoiding potential large swings in FSR posting amounts over a short time period that will not be most reflective of actual prices, providing stability for CCAs who need to post the FSR, and incorporating energy price differences between the summer and winter season.

The semi-annual update in SCE AL 4789-E indicates the FSR posting amount can swing drastically, from the $147,000 minimum to over millions of dollars, from one update to another based on the month chosen to do the calculation.[31] If changes of similar magnitude would occur on a monthly or quarterly basis, it would take up liquidity and credit CCAs could use to hedge their price risk during challenging summer periods or use to fund procurement of new resources to build the supply stack and support clean energy goals.

As described in section III.A.1, the FSR is sensitive to swings the forecast energy price component that, as estimated today, may drastically over or underestimate the actual energy price that will materialize. To provide more stability in the FSR posting, the FSR (1) should not be updated more than once every six months, and (2) should use a broader set of data to more accurately predict the future CAISO market prices.

b. Alternately, should the FSR calculation be modified to provide a six-month procurement forecast period (e.g. Dec-May, Jan-June, May-October, etc.) that accounts for seasonal variation? For instance, should the six-month procurement cost forecast reflect the max or average of the six of the next twelve months that reentry fee may need to cover?

No, the FSR calculation uses forward energy prices by month and energy usage forecasts by month. Changing the alignment of the start and end periods of the FSR will not alter the calculation of the estimated FSR costs which are based on the forward energy quote for the month and the energy usage forecast, not on the average or the maximum cost. As discussed in section VI.A.2.e(ii),

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

the only timing change necessary is to reflect the changes in retail rates that are seasonally differentiated to be consistent with the FSR calculation period.

C. 2.3 FSRs for ESPs and CCAs

a. Should the FSR for ESPs be updated to use third-party financial instruments, consistent with the requirements established in D.18-05-022 and Resolution E-5059? Why or why not?

CalCCA does not have any comments on this question at this time.

b. Notwithstanding the calculation of minimum administrative costs above, should the FSR for ESPs and CCAs follow the same methodology, calculator, and posting requirements? Why or why not?

CalCCA does not have any comments on this question at this time.

D. 2.4 Accessing the FSR

a. Upon notification of a load-serving entity's failure/market exit, does the process adopted in Resolution E-5059 make FSR funds available in a timely enough fashion to provide the necessary liquidity for short-term procurement? If not, what changes are necessary?

CalCCA recognizes the potential timing issues as described by PG&E wherein the costs of energy at the CAISO will become due prior to when revenues from returned customers are realized by the POLR. CalCCA suggests that this can be addressed in one of two ways. If the Commission continues to use the FSR methodology, then the IOU should use balancing account treatment of the costs incurred and allow the collection of re-entry fees and revenues from returning customers to pay off those balances. This may entail inclusion of financing costs, as necessary. Alternatively, the Commission could implement the CalCCA pooling mechanism discussed in section III.B that makes a larger amount available for more immediate use by the POLR in the event of a return of customers.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

July 5, 2022

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON RULING OF THE ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE REQUESTING COMMENTS ON FINANCIAL SECURITY REQUIREMENTS AND REENTRY FEES, AND MODIFYING THE PROCEEDING SCHEDULE

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

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

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

QUESTION 004

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

ANSWER 004

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

ANSWER 004 SUPPLEMENTAL 01

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

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