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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

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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.

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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 <u>*or*</u> 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

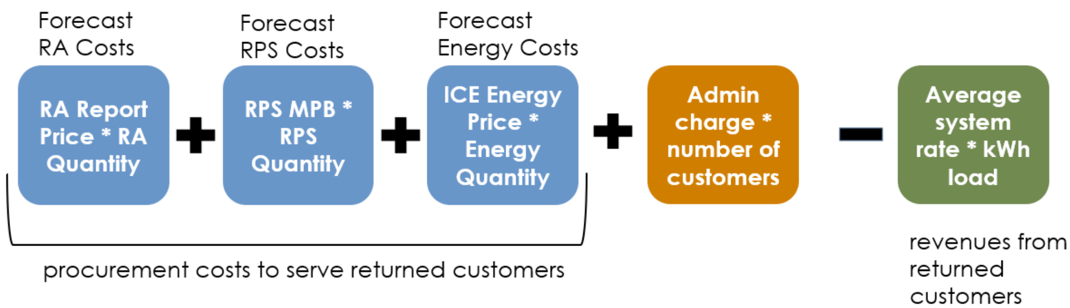
- The posted FSR amount should not be updated more frequently than twice a year.

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

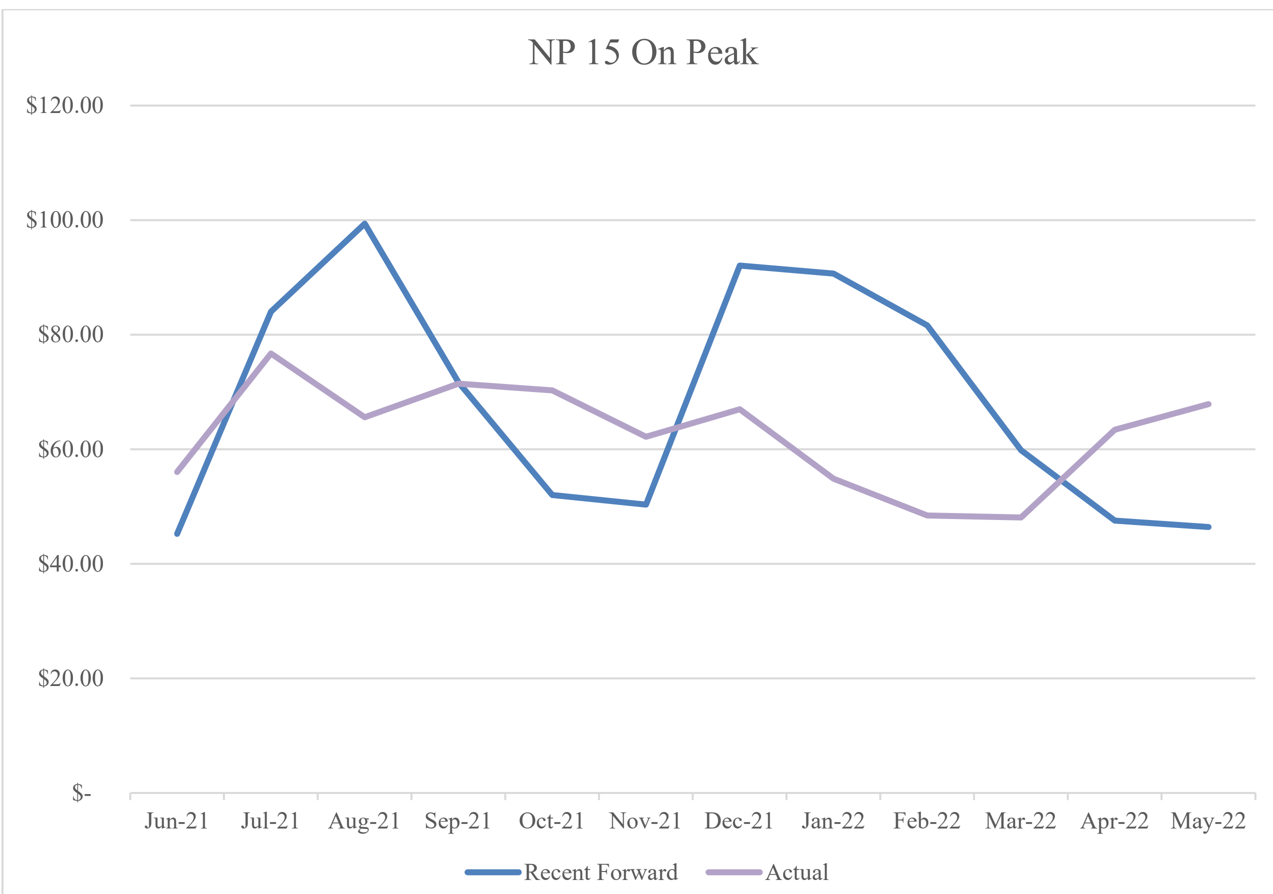
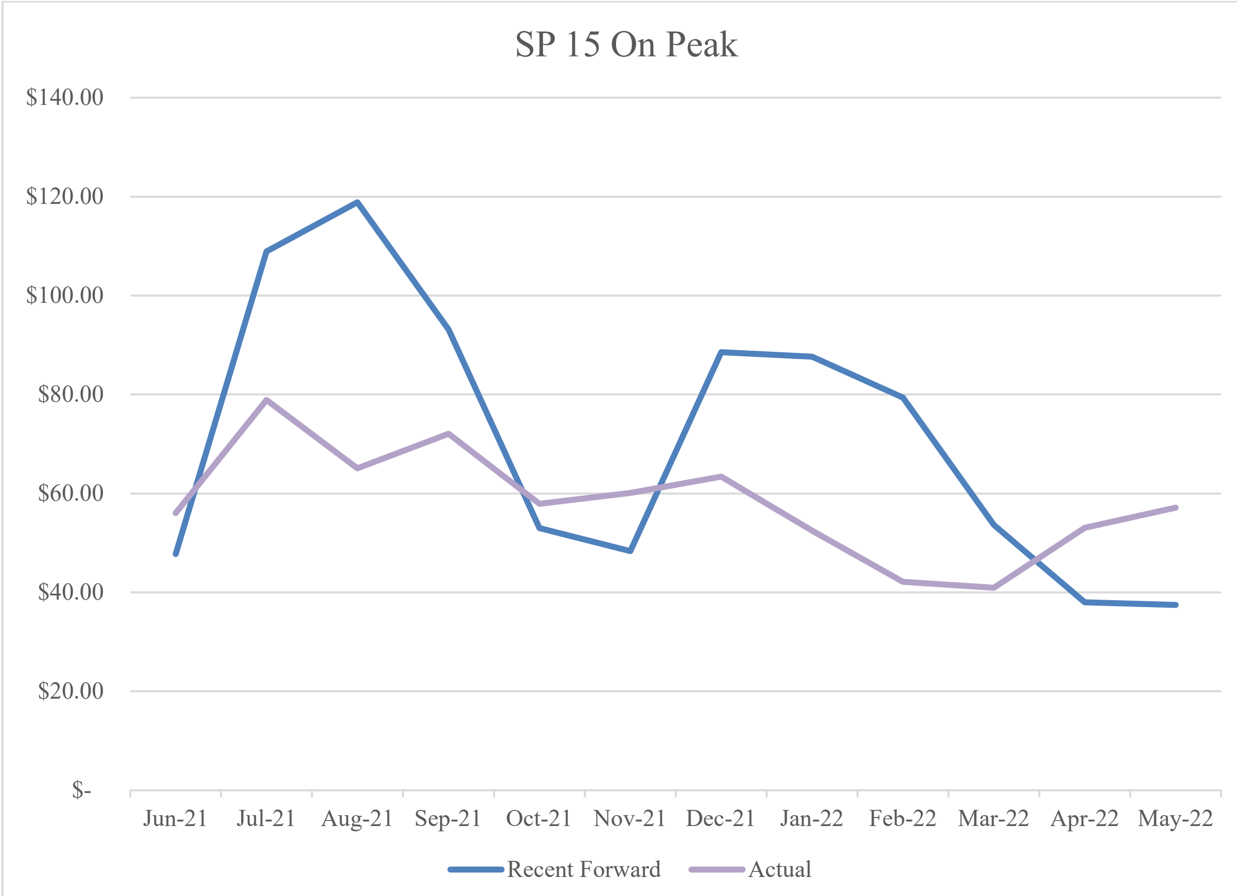


Figure 3



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

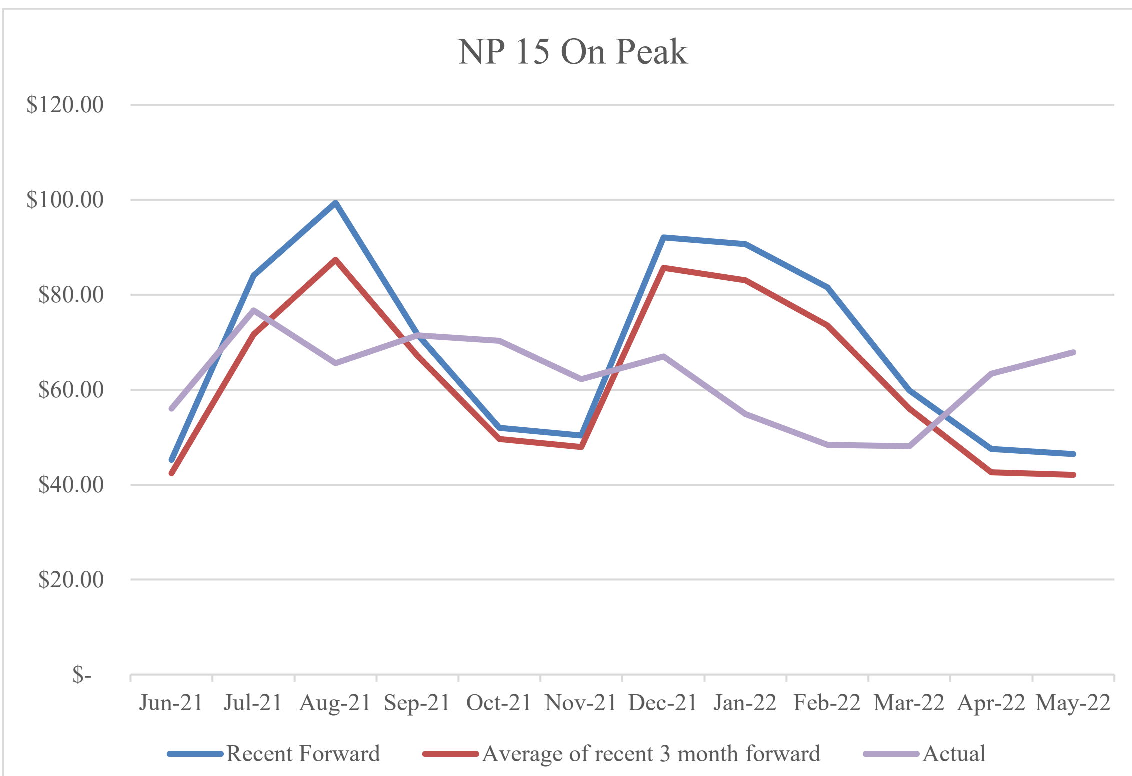
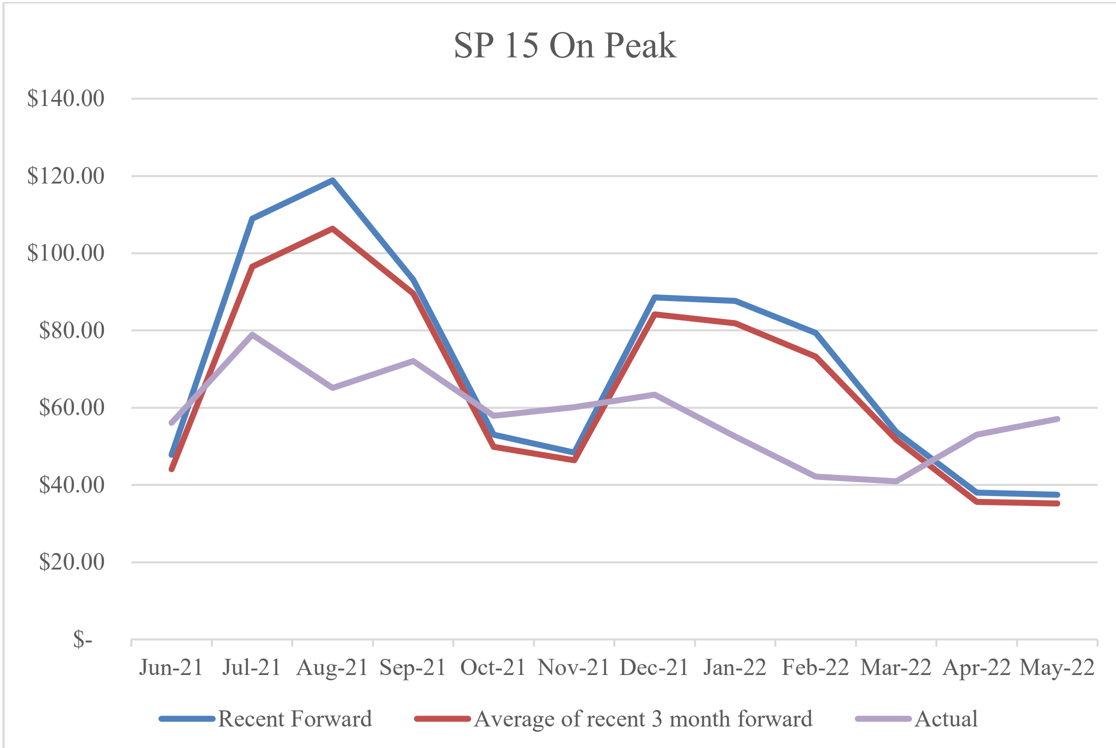


Figure 5



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

[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

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

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:

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[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.

[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*