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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 Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON TRACK 3B.2 PROPOSALS**

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TABLE OF CONTENTS

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The Energy Division Staff's findings regarding shortfalls in energy forward contracting for 2021-2024 do not justify movement from a capacity-based to an energy-based resource adequacy (RA) program design.

The Staff should exclude the Standard Fixed Price Forward Contract (SFPFC) framework for reliability and wholesale price mitigation from further consideration for numerous reasons:

- The SFPFC proposal lacks clarity after more than a year of opportunity for development.
- The proposal would not address the problem it purports to solve.
- Shifting to an entirely new reliability product will materially disrupt the market.
- The proposal imposes structural reliability risks.
- The proposal violates Public Utilities Code §380(b)(5) and §380(h)(5) by failing to "maximize" CCA's "ability to determine the generation resources used to serve their customers; this responsibility is placed in the hands of wholesale market suppliers.
- It remains unclear how the SFPFC interacts with other existing policies; in particular, it raises complex problems and questions regarding the SFPFC interface with the Commission's Integrated Resource Planning and Renewable Portfolio Standard programs and its recently adopted local RA central procurement entity framework.
- The SFPFC framework would be regulated by the Federal Energy Regulatory Commission jurisdiction or, in the alternative, Commodity Futures Trading Commission.
- The proposal unlawfully usurps the role of the CCA in managing risk.
- Simpler, more implementable solutions with fewer legal and market risks are available to address the reliability problems identified by the ED.

The California Public Utilities Commission (Commission) should proceed with further development of the structural proposal advanced by Southern California Edison Company (SCE) and the California Community Choice Association (CalCCA) to address reliability concerns.

The conceptual "slice of day" proposal advanced by Pacific Gas and Electric Company (PG&E) appears to attempt to address the same reliability problems targeted by the SCE/CalCCA proposal but leaves many questions unanswered. However, the proposal's accounting structure may provide insights for continued refinement of other proposals and it merits further discussion in a targeted workshop.

While CalCCA continues to question the Commission's authority to implement a wholesale energy market price mitigation mechanism for all load-serving entities (LSEs), there are more targeted measures that could be pursued in conjunction with the SCE/CalCCA proposal without resorting to the extreme paradigm shift embodied by the energy-based proposal.

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The California Community Choice Association (CalCCA)[1] submit these Comments on Track 3.B.2 Proposals in response to the *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling*, dated December 11, 2020 (Scoping Ruling).

I. INTRODUCTION

The Commission instituted this rulemaking in late 2019 to consider structural reform to the existing resource adequacy (RA) program. The Scoping Memo issued on January 22, 2020, included in Track 3 "[e]xamination of broader RA capacity structure to address energy attributes and hourly capacity requirements…."[2] A year later, a handful of structural reform proposals have been offered, ranging from modifications to the existing structure to the markedly different energy-based approach advanced by Energy Division Staff. The diversity of approaches and the substantial uncertainty around resolution affect all LSEs considering long-term investments and

[1] California Community Choice Association represents the interests of 24 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Jan. 22, 2020, at 7.

procurement. LSEs are concerned that, following structural reform, resource investments made today may not be used to serve their customers following structural form, and they will face greater financial risk if the Commission shifts dramatically to a forward energy-based approach. CalCCA thus encourages the Commission to reduce this uncertainty by narrowing its focus quickly in a single direction and leaving less viable proposals on the side of the road. In making this determination, the Commission should incorporate a preference for structural reform sufficiently compatible with the current structure; this will bolster the confidence of LSEs, developers, and financiers in continuing their work developing much-needed new resources without the specter of "regulatory disqualification" or other disruption through RA reform.

CalCCA recommends removing from contention the energy-based reliability and price mitigation proposal designed by Dr. Frank Wolak and presented by Staff.[3] As Staff themselves have acknowledged, the proposal leaves important unanswered questions, not the least of which center on the foundational legal and policy issues, such as jurisdiction, compliance with state statutes governing reliability[4] (Public Utilities Code §380, and the ability to achieve the state's climate goals. Moreover, even the intricate details of the economic aspects of the proposal are challenging for stakeholders to grasp.

Other less disruptive and more implementable proposals have been advanced by stakeholders that could markedly increase reliability, particularly the proposal advanced by CalCCA and SCE in their August 7, 2020 filing.[5] While CalCCA continues to question the Commission's jurisdiction to pursue wholesale energy market price hedging as a matter of

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3 *See Administrative Law Judge's Ruling on Energy Division's Revised Track 3B.2 Proposal, Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009* (Staff Addendum) at 13-14.

4 CAL. PUB. UTIL. CODE §380(b)(5) and (h)(5).

5 *Southern California Edison Company (U 338-E) and California Community Choice Association's Track 3 Proposal*, Aug. 7, 2020 (SCE/CalCCA Proposal).

jurisdiction, if the Commission continues to press forward, the SCE/CalCCA proposal could be combined with a simpler mechanism like the ED Staff's bid cap requirement to achieve this objective.

The Commission thus should proceed to narrow the range of options in the next two months to focus the proceeding carefully on implementation work following the May decision. After excluding the energy-based approach, other options should be further refined through workshops centered on fleshing out the details of the SCE/CalCCA proposal and further considering PG&E's "slice of day" proposal. Wholesale energy market price hedging mechanisms could be discussed along with these reliability solutions.

II. RESPONSE TO ENERGY DIVISION PROPOSALS

A. Energy Division's Analysis and Conclusions Do Not Justify the Tectonic Shift from a Capacity-Based to a Forward Energy-Based RA Framework

Staff produced supplemental analysis regarding current contracting positions in the energy and capacity markets.[6] The Staff Addendum does not, however, draw a direct connection between its analytical findings and the proposal to move to an energy-based RA framework. Indeed, while the analysis is interesting and provides useful information, it should not be viewed as the justification for an energy-based RA program design.

The ED Staff articulated findings regarding the existing forward energy contracting for 2021-2024 based on submitted LSE Individual Integrated Resource Plan Compliance Filings.[7] Staff concludes: "At an aggregate level, LSEs have only procured on average 65% of their forward energy positions for 2021-2024."[8] Undermining this conclusion, Staff, themselves,

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[6] *See generally* Staff Addendum at 3-14.

[7] *Administrative Law Judge's Ruling on Energy Division's Revised Track 3B.2 Proposal*, *Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009* (Staff Addendum) at 13-14.

[8] *Ibid.*

point out certain shortcomings of the aggregated analysis and overlook others. In addition, CalCCA observes that the analysis' disaggregation of positions by LSE type does paints an incomplete picture of non-IOU positions.

1. The Forward Contract Analysis Contains Uncertainties and Potential Inaccuracies and Should Not Be Used as a Foundation to Move to an Energy-Based RA Framework

The forward contract analysis, as Staff acknowledges, contains uncertainties and potential inaccuracies and, therefore, should not be used to justify a move to an energy-based RA framework. First, as Staff acknowledges, the analysis reveals the likelihood of inaccurate reporting.[9] The analysis points out that the "sum of unspecified non-imports, transfer purchases, transfer sales, and seller's choice contracts" result in a negative value.[10] Because Staff would expect unspecified non-imports[11] to have a positive value, "there is likely the misreporting of information in these values that will require further analysis and likely corrections to the data."[12]

Second, the uncertainty in the analysis is compounded by the conclusion that "a currently indeterminate portion of these contracted energy benefits are likely from solar resources so energy may not be available at the right times to meet load."[13] The analysis does not estimate this quantity nor consider whether storage will be adequate to shift energy to the appropriate periods.[14]

Third, the analysis omits a major product procured by IOUs, CCAs, and ESPs – shaped energy hedging products. LSEs of all types use hedging products to reduce exposure to energy

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9 Staff Addendum at 5-6.
10 *Id.* at 5.
11 While the analysis states that "unspecified imports" would be a positive value, context suggests Staff meant unspecified non-imports.
12 Staff Addendum at 6.
13 Staff Addendum at 7.
14 *Ibid.*

price volatility. While these resources are not appropriate for inclusion in the IRP given their indirect link to system reliability and resource planning, they are highly relevant to ED's concerns regarding market prices and LSE exposure. From the price mitigation perspective, a revised analysis including hedging products would indicate a much lower degree of open position and market price exposure on the part of LSEs.

Fourth, while not clear, the analysis may omit energy offered by RA only resources, which results in an overstatement of the reliability risk implied in the analysis. The Staff Addendum concludes that "RA Only contracts make up 32% of contracted RA, and the large majority of the RA only is attributable to thermal and unspecified resources."[15] This implies that there is potentially a significant amount of energy that will be offered into the market from these resources that is not accounted for in the total contracted energy shown in Figure 1.[16] Assuming the resource complies with its must-offer obligation (MOO), the resource owner has an obligation to offer their resources into the market such that it is available to supply customer demand. Although these resources are not subject to a fixed price or marginal cost requirements, much of this energy will be offered at the profit maximizing price. Additionally, many of these RA only contracts are with resources internal to the CAISO and they are subject to the CAISO's local market power mitigation. Ignoring the potential for additional energy from these resources thus distorts any conclusions drawn regarding energy sufficiency for 2021-2024.

Fifth, the analysis overlooks likely additional energy supplies that could brought to the market in 2021-2024. While the analysis accounts for contracted resources for this period,[17]

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15 Staff Addendum at 14.

16 If Staff made assumptions about the likely amount of energy production from these resources, they are unstated.

17 Staff Addendum at 3.

there may be a limited number of resources added as a result of D.19-11-016 and the most recent Summer 2021 procurement directive that are not estimated.

CalCCA agrees that RA reform is required and has offered, with SCE, a proposal to improve the existing RA program. The Staff Addendum's analysis, however, is incomplete by Staff's own admission and should not be used as a foundation for an energy-based approach to reliability.

2. The Disaggregated Forward Energy Contracting Analysis Provides an Incomplete Picture of CCA Positions

Figure 2 of the analysis overstates potential shortfalls for CCAs and Electric Service Providers of energy for this period by failing to address uncontracted energy from IOU resources in excess of IOU needs. It finds that the IOUs have long positions for energy due to the migration of customers from bundled to CCA or Direct Access service, while other LSEs are short.[18] Staff acknowledges, however, that they "are not able to determine these amounts at this time."[19] The long position, which prudent portfolio management requires to be liquidated in the market, could be substantial. In other words, CCA short positions may be filled, in part, by the IOU excess resources.

In fact, optimizing IOU excess resources through allocation has been the focus of CalCCA's efforts in R.17-06-026. As the Commission is aware, throughout 2019 CalCCA, SCE, and Commercial Energy developed a solution to address excess IOU resources and filed a final report nearly one year ago. Despite these creative solutions that go directly at the question

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18 Staff Addendum at 6.

19 *Id.* at 7.

arising from the Staff's analysis, the Commission has failed to act.[20] The proposal merits the Commission's timely adoption.

B. Standard Fixed-Price Forward Contract Proposal

Staff's Addendum refines its straw proposal for a standard fixed-price forward contract (SFPFC) framework for reliability based on the market design advanced by Dr. Frank Wolak of Stanford University. The framework is effectively a mandatory, full-procurement central-buyer RA framework with an entirely new reliability product. While the proposal is an interesting academic exercise in economics, the proposal does not consider its interaction with applicable law and state policies, as the ED acknowledges. It also lacks a consciousness of the transactional dimension of the market. Consequently, it is difficult to fully understand the operation of the proposal in the current environment. Moreover, the tectonic shift the new framework promises through this new, experimental design would exacerbate the complexity and confusion in an already-uncertain RA market. Finally, despite Dr. Wolak's generous efforts to educate stakeholders, some of the details of the proposal remain elusive. For all of these reasons, CalCCA submits that the energy-based proposal cannot be implemented in a timely manner nor without substantial disruption to resource investment and the RA market.

There is little, if any, disagreement that the existing framework requires improvement to more rigorously manage reliability, but other proposals have been offered that could achieve that same objective with less complexity and disruption and a better chance of timely implementation. CalCCA urges Staff and the Commission to set the energy-based framework aside and turn limited resources and time to these more viable solutions.

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[20] *See generally* R.17-06-026, *Final report of Working Group 3 Co-Chairs: Southern California Edison Company (U-338E), California Community Choice Association, and Commercial Energy*, Feb. 21, 2020.

1. The SFPFC Proposal Lacks Clarity

The ED proposal markedly shifts the reliability paradigm from a capacity product to an "energy-based" product in the form of an SFPFC commencing for compliance year 2023.[21] The mechanism would require "all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons."[22] The requirement would be multi-year, requiring retail sellers to hold SFPFCs covering:

> 100 percent of realized system demand in the current year, 95 percent of realized system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery.[23]

While LSEs would be required to hold SFPFCs to cover their realized load, they would play no role in aggregating the supplies to meet their customers' requirements. The SFPFCs would be procured and allocated to LSEs by a "wholesale market operator" (WMO), which would run forward auctions for the reliability product "with oversight by the regulator."[24] The allocations of hourly energy products with parameters "set by the regulator"[25] would be based on the retail seller's share of realized demand for each month, requiring a true-up auction after realized demand for a delivery period is known.[26] In addition, the WMO would run a "clearinghouse to manage the counterparty risk associated with the counterparty," which today occurs in other wholesale markets.

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21 Staff Addendum at 18.

22 Staff Addendum, Appendix, *Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California,* Dec. 18, 2020 (Appendix to Staff Addendum) at 28.

23 *Ibid.*

24 Appendix to Staff Addendum at 29.

25 *Id.* at 28.

26 Appendix to Staff Addendum at 30.

Unfortunately, Dr. Wolak's proposal raises many critical questions, as ED suggested in its August 7, 2020, draft straw proposal.[27] The straw proposal offered a starting point for further assessment and development that must take place to "move in this direction," let alone implement such a proposal.[28] Neither the Staff revisions nor Dr. Wolak's revised proposal, however, make meaningful progress on these issues. Without filling in these many blanks, the Commission cannot reasonably assess the design's interaction with existing policy to justify moving the proposal forward in contention with other less complex and understandable proposals pending in this Track.

- Would the wholesale market operator be subject to FERC jurisdiction and oversight and, if so, how would the state regulator interface with the market operator?

Perhaps the most significant question arising from the proposal is the identity of the WMO regulator Dr. Wolak's references to a "wholesale" market operator suggest that the regulator would be the wholesale market regulator – today in California the FERC. Indeed, as discussed below in Section II.B.6, there is a strong likelihood that any answer other than the FERC will lead to legal conflict. It is unclear, however, whether the CAISO wants the job of market operator. Moreover, even if the state accepts FERC jurisdiction over the WMO, substantial work must be undertaken to coordinate federal jurisdiction with state goals. Key among the questions regarding placing the CAISO in this position is whether this would "jeopardize clean reliability mandates"[29] given the central focus of CAISO markets on economic efficiency.

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27 *Administrative Law Judge's Ruling on Energy Division's Track 3.B Proposal*, Aug. 7, 2020, Appendix A (Staff Straw Proposal), at 41-42.

28 Staff Straw Proposal at 41.

29 *Ibid.*

- The WMO's management of credit risk for the SFPFC would present significant challenges.

In a multi-year forward market, the credit requirements could be quite large and the requirements for tracking and managing the credit risk could be challenging. If, as discussed above, the WMO would be providing creditworthiness to maintain the contracts with suppliers, that implies that the WMO would require significant capitalization to ensure a robust credit rating.

- How would the SFPFC framework interface with the Commission's IRP program for individual LSEs?

The Staff Straw Proposal called out the need to determine how the SFPFC would interact with "other policy programs such as IRP and the Renewables Portfolio Standard (RPS)."[30] CalCCA shares these concerns, particularly given the risks shouldered by LSEs on behalf of their customers in meeting these requirements. Neither the Staff Addendum nor Dr. Wolak's paper does little to address these central issues.

While the IRP was briefly discussed during the January 8, 2021, workshop, CalCCA remains concerned that the proposal is incompatible with the state's mandate pursuant to Public Utilities Code §452.2(a). State law today requires *LSEs* to bear responsibility for resource development under the IRP. It appears that under Dr. Wolak's proposal, *suppliers* would be responsible for all the procurement and the IRP process would function as a backstop mechanism.[31] This would require yet another revamp of the IRP process.

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30 Staff Straw Proposal at 41.

31 Slides 19 and 37, 1/8/2021 Presentation "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California". Dr Frank Wolak. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Track%203.B.2%20Forward%20Energy%20Workshop%20Slides.pdf

Relegating IRP to backstop function would also leave LSEs unable assemble the resource portfolio that will serve their customers. It leaves a limited role for LSEs in procurement generally, unless they or their counterparties sell the energy from their contracted resources to the WMO, only to be reallocated back through a "peanut butter" spread to all LSEs, including to the LSEs that hold the original contracts. This would mean that an LSE following a particular procurement strategy (to contract with 100 percent renewable energy for its needs, for example) would see its procurement ultimately allocated to all LSEs. Alternatively, if, as Dr. Wolak discussed, an LSE's contracted resources serve to reduce its load that it by and large already covered by SFPFCs, the LSE's customers are then exposed to over procurement costs. Thus, if the current IRP structure is maintained in concert with the SFPFC, "self-procurement" has ever more limited meaning.

Finally, it is unclear how the Commission would have visibility into the source of SFPFC commitments to determine the necessary backstop. Under the existing RA constructs, regulators (the CPUC and the CAISO) ensure that there is sufficient "iron in the ground" and can see the status of those calculations. There are questions about the calculations (how resources are counted and how much should be procured), but the calculations are visible to the regulators. Under Dr. Wolak's proposed mechanism, the WMO ensures that contracts for sufficient energy are procured, but it is not clear how the Commission would obtain visibility to the actual resources behind those contracts. If the generator who has sold an SFPFC contract to the WMO procures other generation to support the SFPFC, these contracts are likely known only to the generator and its counterparty; the WMO would not see the transaction so it would not know which generators are committed to provide the SFPFC.

CalCCA is similarly concerned about the interface of the SFPFC framework with the RPS program. CalCCA appreciates Dr. Wolak's effort to address how the state's renewable energy goals can be advanced in the energy-based framework and how the RPS program could work in concert with the proposal. During the recent workshop, Dr. Wolak suggested that "[r]enewable energy goals can be met by retailers purchasing renewable energy certificates (RECs) equal to annual demand times required renewable energy share." [32] Dr. Wolak has not fully explained, however, how LSEs could meet Bucket 1 requirements, which require that energy remain bundled with its RPS attribute. It is unclear whether his conclusion that "[p]urchase of Bucket 1 REC (energy+REC in same hour) simply implies a different hourly net load for retailer"[33] suggests that the WMO would be clearing on a "net" basis, essentially counting the resources held by the LSE, or if the LSE is left with excess costs of over-procuring energy. Moreover, the proposal lacks any detail regarding the significant complexity of ensuring, consistent with Public Utilities Code §399.13(b), that 65 percent of RPS commitments are from contracts of not less than ten years.

These questions are not trivial. Even if they could be answered, however, modifying the IRP and RPS programs around the SFPFC construct makes little sense if, as the case is, there are other simpler approaches that achieve the Commission's objectives.

- How would the SFPFC framework interface with the local RA CPE?

The Staff Straw Proposal recognized the need to harmonize changes to system reliability with the recently adopted changes in the local reliability framework.[34] Beginning in 2022, the Local RA CPE will be responsible for procuring all local RA for all LSEs.[35] It is likely that the

32 Slide 39, 1/8/2021 Presentation.
33 Slide 39, 1/8/2021 Presentation.
34 Staff Straw Proposal at 42.
35 *See generally* D.20-06-002.

CPE will procure half or more of the CPUC-jurisdictional system RA need in the course of procuring local resources.

It is unclear how, if at all, the SFPFC has contemplated its overlap with the local RA needs now the responsibility of the CPE. It is difficult to imagine maintaining a capacity-based CPE, as recently adopted, for local reliability while moving to an energy-based approach for system reliability. Local RA includes system RA, so applying two very different models to resources with both attributes seems confusing, at best. Moreover, local RA procurement – while market-based in many respects – is often driven primarily by grid engineering needs and contingency planning which are not accounted for, and perhaps incompatible with, the SFPFPC proposal.

If the two programs could not be harmonized, and the Commission were to move to the SFPFC, this would mean either scrapping the recently adopted local RA framework or leaving the program in place for only one year. The latter would make no sense since the local RA framework includes a three-year forward requirement of a capacity product. In addition, this would bring substantial dysfunction and uncertainty in the current RA markets. The Commission simply cannot move forward to further consider the SPFPC approach without answering this foundational question.

2. The SFPFC Would Not Address the Problem It Purports to Solve.

Beyond the significant open-ended issues discussed above, the SFPFC proposal fails to solve the very problem that it purports to solve. Dr. Wolak cites the "reliability externality" as a motivation for the proposal,[36] suggesting that when there are reliability shortfalls, "no retailer

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36 Appendix to Staff Addendum at 25-27.

bears the full cost of failing to procure adequate amounts of energy in advance of delivery."[37]

He continues:

> A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as another retailer of the same size that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.[38]

Dr. Wolak's proposed structure does not eliminate this problem. Shortfalls in supply are still possible if the forward SFPFC contracting is not sufficient to cover the ultimate "realized demand" due to forecast error, generation and transmission contingencies, or suppliers' failure to deliver. In other words, the shortfalls could still occur, but without the legal and regulatory mechanisms that might be used to address the problem in the case of retail sellers under the RA program.

The proposed remedy for the shortfall will be for the procurement of energy by the suppliers in the market at high prices with the cost borne by suppliers. This is precisely the case for retailers, today, with inadequate hedging now. Suppliers will make their decisions about securing sufficient resources based on their assessment of the expected value of securing sufficient resources to meet the expected needs at the costs, versus the potential losses for being short. Especially if the energy procured is more than the expected demand, and some will be expected to be sold back after the period, suppliers may decide it is not worthwhile to procure all required energy and will plan to procure some of the excess energy that will be sold back. This would also be more likely if there is a cap on the potential costs of not having enough energy.

[37] *Id.* at 25.
[38] *Ibid.*

Since it is unlikely that the energy market will be completely uncapped, there will be limits on how much suppliers will be willing to spend to avoid the potential losses.

Simply shifting the responsibility for making the risk calculations on RA supply from the LSE to suppliers does nothing to "internalize" the cost of curtailment. In fact, arguably, the problem has been made worse. While LSEs may have a direct concern for reliability and the potential for curtailment of their customer loads, suppliers' behavior is limited solely to the economics of their strategy. Further, the regulator of the suppliers might have a different view of how costs, benefits and risk tradeoffs of the supply portfolio than would the regulator of the LSEs, potentially leading to different outcomes.

3. Shifting to an Entirely New Reliability Product Will Materially Disrupt the Market

The Staff Addendum would move the reliability market from today's capacity product to a new, untested, and yet undefined energy-based product. While acknowledging that this will require a transition, the Addendum underestimates the market disruption the transition will cause over a period of the next six years -- a period during which the state cannot afford more market confusion and uncertainty.

Having just adopted a massive restructuring of local RA procurement through the RA CPE proceeding, the Commission is already contemplating additional changes to the existing structure for 2022 in Track 3B.1, leaving parties very hesitant to forward contract. That uncertainty is likely to remain until the new market structure is implemented. As an example of these potential complexities, consider an LSE that has a long-term contract with a solar facility for the energy produced. In order to avoid having double procured this energy (since it will be allocated its share of the total system energy in the form of SFPFC), it appears that the energy from the solar facility will need to be bundled into an SFPFC and sold to the WMO. The LSE will either need to procure the additional energy to allow it to deliver the energy profile for the SFPFC, a complicated transaction carrying potentially large risks, or in the alternative find a generation company or marketer willing to pay for the power in order to combine it with its own resources to create a SFPFC. Especially before any of these contracts have been delivered or even before the auction has been run this seems like a daunting task with potentially large risks.

Even if the program is implemented, because new market structures (and especially new structures never implemented elsewhere) always require adjustments as lessons are learned, uncertainty will continue over the next couple of years until the rules settle. There is no certainty that this approach, in fact, would yield higher reliability than other modified capacity-based frameworks but there is certainty that it would cause market disruption on the road to implementation. Grid reliability would be best served by avoiding unnecessary significant, continuous disruptions.

As an example, consider an LSE negotiating a long-term contract for a new hybrid solar and storage facility. The LSE, developer, and financier now must contemplate a new and ill-defined set of obligations for how the energy from the project is provided through the SFPFC process, which may have dramatic and material impacts on the expected revenue stream from the facility. One interpretation suggests that the developer, or perhaps the LSE, will be obligated to bundle the energy from the hybrid facility with a firm resource – perhaps one held by a third-party merchant generator – in order for the resource to even be considered against that LSE's reliability obligations. An alternate interpretation implies that the resource could be bid directly into the SFPFC process but at greatly reduced value. The level of complexity, uncertainty, and unknown risks as these details are determined over the course of multiple years would likely significantly chill the ability of the counterparties to come to an agreement which would result in the financing and development of new resources.

4. The SFPFC Proposal Imposes Structural Reliability Risks

A central feature of "energy only" proposals, and, under CalCCA's current understanding of the SFPFC energy-based proposal, is the transition of the planning and analysis functions for capacity sufficiency from regulators and LSEs to energy suppliers. Specifically, this occurs through the shift from administratively determined capacity counting processes (RA, IRP) to market incentives for suppliers to ensure firm supply from portfolios including intermittent resources. The SFPFC proposal intends to "[let] suppliers figure out least cost way to meet system demand for energy and ancillary services" and instead limits regulatory focus to the "primary reliability problem…adequate energy to serve demand."[39] This appears to be premised on the notion that it is being implemented in a region with significant excess firm capacity that simply needs be made available to backfill the intermittency of the renewable fleet. While this may have been a reasonable (albeit untested) hypothesis when this proposal was initially submitted into the record on August 7, 2020, this premise was conclusively disproven on August 14, 2020.

While there is some ambiguity, CalCCA understands that the SFPFC proposal addresses this planning function as follows[40]:

a) Demand uncertainty may be addressed by the regulator (CPUC) increasing the forward energy purchase quantity to provide a buffer.

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[39] Slide 24; 1/8/2021 Presentation.

[40] Market Design in a Zero Marginal Cost Intermittent Renewable Future Section 3.4, Mechanics of Standardized Forward Contract Procurement Process. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K182/344182682.PDF

b) Intermittent resource energy is limited on an annual basis by the regulator in a manner similar to but more conservative than the Effective Load Carrying Capability (ELCC) valuation.

c) Intermittent resource capacity valuation is deferred to the market to determine capacity sufficiency.

Treatment of demand uncertainty does not depart dramatically from the current structure, in which regulators (CPUC, CEC, CAISO) determine a reasonable buffer on expected peak demand, currently the Planning Reserve Margin. CalCCA does not take issue with this approach, though notes that this is a significant departure from "energy only" markets such as the structure within ERCOT.

Treatment of renewable resource energy output on an annual basis provides unclear benefits from CalCCA's perspective. Renewable resource energy output is neither evenly nor randomly distributed but tied to more- or less-predictable daily and seasonal patterns. It is unclear how an annual energy constraint provides suppliers, LSEs, or regulators with sufficient information or incentives to make good decisions regarding renewable energy output, and seems to be simply intended to prevent renewable resources from receiving outsized revenues from SFPFCs beyond their minimum expected ability to produce.

Beyond the above structures, the proposal appears to defer the remaining renewable resource valuation and accounting questions to market forces – ensuring that hourly capacity from individual resources or resource portfolios is "firm" appears to be deferred strictly to suppliers. Specifically, the SFPFC construct asks suppliers to estimate their ability to provide firm energy with non-firm resources and sell it – with strict penalties – years in advance, and it is unclear what process, if any, would ensure unified assumptions, risk preferences, and other methodological choices are aligned between sellers beyond market forces. In effect, while the SFPFC does provide a stronger financial incentive to be able to fulfill forward commitments, fundamentally, it leaves suppliers in the same position as regulators today – grappling with uncertainty regarding future output from renewable resources. It is unclear why suppliers would have better information on future weather conditions than regulators and LSEs, or, more importantly, would make more societally beneficial determinations regarding resource need than would regulators and LSEs, which more directly face the reliability externality than do suppliers.

It is worth viewing this issue through the lens of the proposal's primary strategy for addressing hourly variability in renewable resource output – "cross-hedging" between intermittent and firm resources. Rather than administratively determining intermittent resource value, as is currently done through ELCC adjustments and other means, the proposal envisions "cross-hedging"[41] between dispatchable resources and intermittent resources as a strategy for suppliers to ensure resources are capable of meeting their hourly obligations from variable renewable resource production.

Imagine a supplier seeking to provide 100 MWh of firm hourly energy from 100 MW of wind for a September showing, as illustrated in ***Table 1***. Under the current program, a supplier would show 100 MW of wind resources, valued at 15 MW of RA capacity (15% of its nameplate value) in September, as well as 85 MW of firm resources, for a total of 100 MW of RA capacity. This could be conceptually viewed as offering 100 MWh of firm energy during the September

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[41] Slide 34; 1/8/2021 Presentation "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California". Dr Frank Wolak. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Track%203.B.2%20Forward%20Energy%20Workshop%20Slides.pdf.

peak hour, with some administratively determined risk tolerance for the wind resource producing more or less than 15 MWh.

Under the SFPFC construct (simplified as a MW obligation for illustration), the supplier's risk tolerance will dictate the degree to which it hedges a wind resource with firm resources – a risk-loving supplier might assume its wind resources will produce at its median historic energy output (50 MW]) and back its wind fleet with only 50 MW of firm capacity. In contrast, a risk-averse supplier might assume its wind resources will produce only 5% of nameplate capacity, backing its wind resources with 95 MW of firm capacity. CalCCA understands that, under the proposal, there is no provision to prevent suppliers from making either of the above decisions so long as, over the course of a year, the wind resource does not offer more than its expected annual energy output.

The alternative would require significant oversight and verification of actual generation of every resource in the state, greatly increasing the regulatory burden.

	Current RA Structure	SFPFC		
		Risk-Averse Supplier	ELCC-Based Supplier	Risk-Loving Supplier
Wind (Nameplate)	100 MW	100 MW	100 MW	100 MW
Wind (Assumed Value)	15 MW	5 MW	15 MW	50 MW
Fossil Backup	85 MW	95 MW	85 MW	50 MW
NQC Value (Current Methodology)	100 MW	110 MW	100 MW	65 MW
NQC Deficit (Current Methodology)	0 MW	-10 MW	0 MW	35 MW

Table 1: Fossil Resources Required to Firm 100MW Wind Resources in September – Comparison of Different SFPFC Supplier Approaches

In either scenario, it is true that the supplier will face economic consequences for its decisions when the wind resources are called to deliver – however, society will bear the reliability risk for the risk-loving supplier making a bad gamble. Further, unlike today, when the regulator establishes the level of reliability, the regulator will not know if those entities supplying SFPFCs are risk averse or risk-loving, so it will not fully know what level of reliability has been procured behind the forward contracts. Especially early on in such a market, before entities have experience managing these risks this seems to provide a wide range of potential outcomes including many which do not ensure system reliability.

Collectively, this results in a resource supply stack (for capacity) which is dictated not through modeling and planning, but through the individual analyses and decisions made by suppliers. While suppliers may, overall, make informed, incentive-aligned decisions, there is significant risk associated with transferring the responsibility and oversight of this system planning work from LSEs and system planners to suppliers with a wide range of risk profiles. In particular, there is risk that suppliers may not internalize the risk of high-impact, low-probability events – the exact types of risks the electric grid has traditionally planned for and which form the basis for the reliability externality.

The proposal appears to discount this risk based on two factors – one, a presumption that there is sufficient firm, physical capacity to always meet peak demand, and two, a presumption that economic incentives will rise to the level that suppliers will not want to take risks with intermittent resources, thereby pushing their assumed capacity value to zero. Although this transition to market incentives to ensure intermittent renewable resources are sufficiently firmed seems central to the proposal's "least-cost solution" to reliability in a high-renewables paradigm, paradoxically, there has also been discussion of regulatory intervention for resources which are assigned valuations which exceed their likely production, though it is unclear that this envisions expanding the annual energy constraints to an hourly accounting.[42] Further, if it is an expansion to an hourly accounting scheme, it is unclear whether this would act as a standard metric or as an

[42] Slide 19; 1/8/2021 Presentation.

enforcement mechanism for suppliers significantly overestimating production. If the former, the solution for renewable resources begins to look a lot like today's ELCC methodology – which administratively determines intermittent resource value and may over- or under-estimate actual delivered energy, but does so with an eye towards conservative assumptions which ensure reliability, breaking the proposal's efforts to reach a more least-cost system than today's structure. If the latter, it is likely that the cumulative resource valuation from suppliers will not equal the level and mix of resources which would be determined by a central procurement process, leaving uncertainty as to whether the structure truly provides for a reliable system.

5. The SFPFC Proposal's Centralized Approach Violates Public Utilities Code §380(b)(5) and §380(h)(5) by Failing to "Maximize" CCAs' Ability to "Determine the Generation Resources Used to Serve Their Customers"

The Legislature directed the Commission not once, but twice, to ensure that the resource adequacy framework secures CCA procurement autonomy. Public Utilities Code §380(b)(5)[43] requires the Commission to "establish resource adequacy requirements for all load-serving entities" in a way that will "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers." §380(h)(5)[44] similarly requires the Commission to "determine and authorize the most efficient and equitable means for … [e]nsuring that community choice aggregators can determine the generation resources used to serve their customers." The SFPFC proposal fails this test entirely, appearing not even to try to check this box. In addition, §380(c) requires individual LSEs to "maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves."[45]

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43 CAL. PUB. UTIL. CODE §380(b)(5).
44 CAL. PUB. UTIL. CODE §380(h)(5).
45 CAL. PUB. UTIL. CODE §380(c).

As discussed above, it is unclear how the SFPFC proposal interfaces with the existing IRP and RPS frameworks, if at all. Assuming no change, LSEs could procure whatever resources they choose, but their choice would be negated by the auction structure, leaving them no influence over which resources are actually "used to serve their customers." In short, Dr. Wolak's proposal could not be adopted without a change in law.

6. FERC Jurisdiction Is Likely to Be Asserted.

It is unclear from the SFPFC proposal the roles that the CAISO and FERC would play in the framework. FERC has generally been willing to allow the Commission to establish RA capacity requirements for its LSEs within limits. California will go beyond those limits, however, if the Commission intends to regulate the "wholesale market operator" or directly or indirectly dictate wholesale energy prices.[46]

The FERC's jurisdiction arises from the Federal Power Act, which was originally enacted in 1920 and has been amended numerous times.[47] The FPA grants FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales, requiring "just and reasonable" rates,[48] prohibiting "undue preference or advantage",[49] and conferring authority to rectify any action that violates these statutory directives.[50] Consequently, Commission decisions that affect wholesale sales are likely to trigger FERC jurisdictional oversight.

FERC, on occasion, has permitted state laws and programs in several contexts where state and federal jurisdiction overlap. In fact, the Commission's program today relies on the

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46 It is also possible, given the nature of the product contemplated by the SFPFC, that the Commodity Futures Trading Commission would need to grant a waiver similar to what it did for FERC's Congestion Revenue Rights markets.

47 16 U.S.C. §§ 791, *et seq.* (the FERC was preceded by the Federal Power Commission).

48 16 U.S.C. § 824d(a).

49 16 U.S.C. § 824d(b).

50 16 U.S.C. § 824e(a).

overlap between its jurisdiction over reliability concerns and FERC's jurisdiction over wholesale sales. For example, in Order 719, FERC required regional transmission organizations and independent system operators to permit "a qualified aggregator of retail customers to bid demand response on behalf of retail customers" directly into organized, FERC regulated markets.[51] Recognizing the interface of the program with retail jurisdiction, FERC allowed states to opt out. It noted that its intent "was not to interfere with the operation of successful demand response programs, place an undue burden on state and local retail regulatory entities, or to raise new concerns regarding federal and state jurisdiction…."[52]

However, where a state law or program is so "tethered" to or directly impacts participation in the wholesale market, FERC is likely to assert jurisdiction. FERC authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce.[53] In *FERC v. Elec. Power Supply Ass'n*,[54] the Supreme Court observed that the FPA obligates FERC to oversee "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with' interstate transmissions or wholesale sales —as well as "all rules and regulations *affecting* or pertaining to such rates or charges."[55] The Court also approved a "common-sense" construction of the FPA's language which "limit[s] FERC's 'affecting' jurisdiction to rules or practices that '*directly* affect the [wholesale] rate.'"[56]

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[51] *Order 719*, 125 F.E.R.C. 61071 at *459-60 (Oct. 17, 2008) (amending 18 C.F.R § 35.28).
[52] *Id*. at *128.
[53] *Cal. Pub. Util. Comm.*, 132 F.E.R.C. 61047, 61335 (July 15, 2010); 16 U.S.C. § 824(d) (Under the FPA, the term "sale of electric energy at wholesale" means "a sale of electric energy to any person for resale.")
[54] 136 S.Ct. 760 (2015).
[55] *Id.* at 773 (2015) (quoting 16 U.S.C. § 824d(a))(emphasis added).
[56] *Id.* at 774 (quoting *Cal. Indep. Sys. Operator Corp. v. FERC,* 372 F.3d 395, 403 (D.C. Cir. 2004)).

Caselaw establishes rough guidelines for what constitutes a "direct" impact on the wholesale market. In *Hughes v. Talen Energy Mktg., LLC.,*[57] the Supreme Court ruled that a program designed by the State of Maryland to provide subsidized price support to encourage development of new resources was preempted by federal law.[58] The program provided "subsidies, through state-mandated contracts, to a new generator, but condition[ed] receipt of those subsidies on the new generator selling capacity into a FERC-regulated wholesale auction."[59] FERC sought to preempt the program due to its effect on wholesale markets, noting the tension with state policy:

> Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity.[60]

The Fourth Circuit affirmed FERC's conclusion, reasoning that the program "functionally sets the rate that [generator] receives for its sales in the PJM auction," which is a FERC-approved organized market.[61] The Supreme Court agreed: "[b]y adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[62]

Just as FERC successfully asserted its jurisdiction in Maryland because of the state's direct interference in the wholesale market, it is highly likely that a similar conclusion will be reached should the Commission implement the proposed energy-only construct with the Commission at the center. Imposing the SFPFC requirement and obligating participation in the

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57 136 S.Ct. 1288 (2016).
58 *Id*. at 1290.
59 *Id*. at 1293.
60 *Id.* at 1296 (citing *PJM Interconnection,* 137 F.E.R.C. 61145, 61747 (Nov. 17, 2011)).
61 *Id*. (quoting *PPL EnergyPlus, LLC v. Nazrian*, 753 F.3d 467, 476-77 (4th Cir. 2014)).
62 *Id*. at 1297.

SFPFC auction potentially would result in a change in the mix of resources that would be developed to meet the requirement than the mix of resources that would have been developed under a different RA construct. This different mix would affect electricity market prices and thus would invite FERC jurisdiction.

Even if FERC were to decline jurisdiction over the SFPFC auction, it seems likely that the SFPFC transactions would be subject to Commodities Futures Trading Commission (CFTC) regulation over swap transactions or that a waiver from such regulation would need to be requested by the entity running the SFPFC auction. In 2010, Congress expanded the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) to broaden the scope of CFTC exclusive jurisdiction. "In particular, it expanded the Commission's exclusive jurisdiction, which had included futures traded, executed and cleared on CFTC-regulated exchanges and clearinghouses, to also cover swaps traded, executed, or cleared on CFTC-regulated exchanges or clearinghouses."[63] Without FERC oversight and a waiver from the CFTC, which the CAISO has previously obtained for its Congestion Revenue Rights market, market operation would fall to CFTC. This out-sized regulatory hurdle would need to be overcome prior to implementing the proposed SFPFC auction mechanism. Critically, however, it virtually ensures that the market operation could not be overseen by a California regulator.

A more straightforward conflict would exist if the SFPFC construct and market was only under the jurisdiction of the CPUC. The CAISO has other entities in its markets that are not subject to CPUC jurisdiction and would likely not participate in the SFPFC market. In order for those other CAISO members to use the SFPFC for RA, the CAISO would need to adopt an SFPFC RA construct and this would have to be approved by FERC. The CAISO currently has its

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[63] CFTC swap regulation Final Order, 78 Fed. Reg. 63 (April 2, 2013), citations omitted. https://www.cftc.gov/LawRegulation/FederalRegister/FinalRules/2013-07634.html

own tariff requirements for RA. These tariff requirements provide some leeway to local regulatory authorities to establish their own RA rules, but the SFPFC construct is so different from the existing CAISO tariffs that it is not apparent how LSEs or the WMO would provide the necessary RA showing to the CAISO. Companies selling SFPFCs to the WMO determine how to manage the risks through the cross-contracting, but which resources are being used for the forward energy purchases are not disclosed to the WMO, so it is unclear how the WMO would construct the resource showing required under the current CAISO tariff.

7. The Proposal Unlawfully Usurps the Role of the CCA in Managing Risk

The Commission has jurisdiction over CCAs only in very discrete areas defined by the Legislature. It certifies receipt of implementation plans,[64] certifies CCA IRP plans following approval of the CCA's governing board, [65] ensures CCAs comply with RPS requirements,[66] permits CCAs to submit proposals to satisfy their portion of renewable integration needs,[67] addresses cost shifting,[68] and is responsible for CCA compliance with RA requirements within the parameters of §380.[69] It has no jurisdiction, however, over a CCA's ratemaking or financial conditions. Contrary to this legislative framework, the Staff Addendum in large part seeks to require specific levels of energy price hedging – a financial aspect of a CCA's business that lies beyond the Commission's jurisdiction.

Apart from the jurisdictional question, requiring price hedging has much different implications for IOUs than for CCAs. The Commission regulates the energy price hedging of the

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64 CAL. PUB. UTIL. CODE §366.2(c)(7).
65 CAL. PUB. UTIL. CODE §454.52.
66 CAL. PUB. UTIL. CODE §399.15(a).
67 CAL. PUB. UTIL. CODE §454.51(d).
68 *See, e.g.,* CAL. PUB. UTIL. CODE §366.2(d), (e), and (f).
69 CAL. PUB. UTIL. CODE §380(e).

IOUs, but they have this authority only because of their obligation to ensure that IOU retail rates are just and reasonable, including the costs incurred in such hedging. CCA ratemaking, however, is squarely outside of the Commission's jurisdiction. If CCAs attempt to raise rates to cover hedging costs they risk losing customers who return to the IOUs without the benefit of a PCIA charge to ensure that those costs are recovered. In contrast, an IOU is guaranteed the costs of recovering resources procured for hedging purposes through the PCIA. The Commission cannot require a specific amount of hedging for CCAs without then ensuring – as they do with the IOUs -- that they are able to recover those costs.

8. Simpler Solutions with Fewer Legal Infirmities and Market Risks Are Available to Address the Problems Articulated by Energy Division

There are two dimensions to the SFPFC proposal: financial hedging and supply reliability. The Staff Addendum proposes the most complex, disruptive, and legally fraught approach to achieve these two ends. CalCCA recommends pursuing other proposals – chiefly, the SCE/CalCCA proposal – rather than embark on Professor Wolak's grand experiment. The SCE/CalCCA proposal, subject to refinement (much less refinement than would be required to develop and implement Professor Wolak's proposal), would achieve the Staff's identified reliability objectives.

While CalCCA has strong concerns that the proposal may not achieve its stated reliability benefits, as discussed in Section II.B.4, to the extent it does so, it likely does so in the manner least simple and least easy to implement of any of the proposals before the Commission. In contrast to the current structure, the SCE/CalCCA proposal and the newly proposed PG&E slice-of-day proposal, the SFPFC proposal does not explicitly ensure sufficient physical resources are available for CAISO to dispatch when required, and appears to rely primarily on market forces to ensure resource sufficiency. It abandons the central structures of the three aforementioned alternatives – all of which rely on an LSE-based, forward-looking obligation counted in capacity and/or energy, instead establishing a convoluted market structure which the state must hope will induce economically efficient behavior. Finally, it envisions either integrating this process into CAISO or perhaps establishing a new entity, from scratch, to operate this market in parallel to CAISO – an entity which may likely fall under FERC jurisdiction regardless. Each of these shifts would take years to envision, design, calibrate, and implement; collectively, it is hard to envision a smooth transition to this new structure in place by 2025, let alone with sufficient lead time to rectify resource shortages by then.

Similarly, if the Commission is intending to address perceived market power concerns or ensure LSE hedging – issues which are not obviously in scope for the Resource Adequacy program – the SFPFC proposal is an incredibly complex method to achieve these goals. It may also not help to address these concerns. Constructing the required hedging portfolios to support sales of SFPFC appears to be very complicated with large amounts of potential risk. It is likely that large generation or power marketing companies would have significant advantages in constructing such portfolios, both because they are of a size to manage the potential risks and because they already have a large portfolio of resources which will make it easier to assemble the required portfolio. The number of such companies is likely limited and thus the number of companies able to offer SFPFCs to the WMO would be limited and market power will remain an issue.

The following table compares the SFPFC with the SCE/CalCCA proposal, showing that the SCE/CalCCA addresses the same issues, but without the massive shift in the Resource Adequacy paradigm that would be required by the SFPFC approach.

SFPFC Element	SCE/CalCCA Track 3B.2 Proposal Element
The firm capacity values from the existing capacity-based long-term resource adequacy approach can be used to limit the amount of SFPFC energy a supplier can sell. [Appendix at 30]	Develop and apply NQC for all RA resources in a process similar to today.
The firm capacity value multiplied by number of hours in the year would be the maximum amount of SFPFC energy that the unit owner could sell in any given year… This mechanism uses the firm capacity construct to limit forward market sales of energy by individual resource owners to ensure that it is physically feasible to serve demand throughout California during all hours of the year… [Appendix at 31]	Develop NQE for all resources. Detailed methodologies to determine the NQE for various types of use-limited resources will need to be developed during implementation workshops.
SFPFCs are shaped to the hourly system demand within the delivery period of the contract. [Appendix at 28]	Develop a load curve utilizing California Energy Commission ("CEC") load forecast data on an LSE basis. The details of load forecast methodologies will be developed in consultation with the CEC, including methods for LSE data on load modifiers and local load shapes.
Expected renewable output would be addressed explicitly by limiting the amount of energy that could be sold (see Step 2).	Develop expected renewable energy from wind and solar using LSE's portfolio of resources and an energy profile for those resources from the IRP to account for expected energy from wind and solar resources.
No netting of wind and solar output.	Net the load curve with the wind and solar output.
Account for load on an hourly forecast basis.	Rank order the net load from highest to lowest to create a net load duration curve based on an hourly forecast
The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auction. [Addendum at 30]	Establish the capacity (NQC) need as the highest net load hour.
See above.	Establish the energy need (NQE requirement) as the sum of the positive hourly loads for all hours. This represents the area under the net-load duration curve.
Not addressed.	Commission provides notice to LSEs of their individual allocations of Cost Allocation Mechanism and Central Procurement Entity procurement with sufficient advance notice to enable effective procurement by those LSEs. The allocations count toward the LSE's NQC and NQE compliance requirements.

SFPFC Element	SCE/CalCCA Track 3B.2 Proposal Element
These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month… The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. [Appendix at 29]	LSE shows resource portfolio to meet RA need, including dischargeable storage, dispatchable renewables, and thermal resources under RA contracts.
To the extent that there is concern that these financial incentives are insufficient for generation unit owners to address all local reliability issues, separate SFPFC products could be created for regions of the state. For example, there could separate SFPFCs for the demand nodes in Northern California and the demand nodes in Southern California. [Appendix at 33]	Local RA CPE procures sufficient local resources.
Each LSE is required to meet their share of the realized energy need.	Portfolio is assessed to see if there is sufficient energy available from the resources (including storage resources but net of energy required to charge storage) to meet the net load needs of the LSE during the hours of positive net load.
Storage is not directly accounted for, since it doesn't produce energy, but it would be an important tool for firming up intermittent resources. This mechanism ensures long- term resource adequacy in markets with retail competition while also allowing the short-term wholesale price volatility that can finance investments in storage and other load-shifting technologies necessary to manage a large share of intermittent renewable resources. [Appendix at 24]	If there is storage in the LSE portfolio, the energy need above is assessed to determine if there is excess energy necessary to fully charge the storage to deliver the necessary capacity.
A central entity would run SFPFC auctions.	The NQC and NQE obligations would be fulfilled by LSEs to meet their own load requirements via bilateral transactions.

If the Commission's goal is to mitigate market power through price controls, incremental solutions could be combined with the SCE/CalCCA proposal. This requires, however, that the Commission implement an approach that does not significantly affect the operation of the wholesale markets regulated by FERC and does not usurp a CCA's financial hedging strategies.

C. Bid Cap Requirement Proposal

The Staff Addendum proposes adoption of a price cap in RA contracts set at the "higher of $300/MWh and the resource-specific default energy bid and that these default energy bids should capture any of these gas price anomalies."[70] The ED would review bidding by RA sellers to ensure compliance. If a seller failed to comply, the LSE as buyer would be referred for non-compliance.

While the proposal would exert some level of control over the exercise of market power by suppliers, the control would be incomplete and the proposal raises three problems: jurisdiction, administrative complexity, and unintended consequences. CalCCA acknowledges, however, that if the Commission continues on its path to require a market price mitigation mechanism for the wholesale market, the Staff's proposed mechanism merits consideration.

1. The Bid Cap May Have Limited Effectiveness During Times of Constraint

The bid cap will not necessarily ensure that the prices bid by importers are at or below bid cap if the RA bids are not the marginal resources at the intertie. That is, if higher cost bids set the clearing price at the overall CAISO bid cap, then the RA imports would not face price risk for failing to perform. So there is no assurance that during times of significant constraint, when price concerns are the greatest and imports may well be the marginal resource, the cap will have its desired effect.

2. The Bid Cap May Infringe on FERC Jurisdiction

Aside from the bid cap's effectiveness, wholesale market power regulation lies within the scope of FERC jurisdiction and is currently reviewed by the CAISO's Department of Market Monitoring. This is not within the Commission's purview, as a matter of law. No doubt the Commission would argue that its price-cap regulation is a function of regulating procurement rather than wholesale market transactions. This may be a distinction without a difference in practice. As discussed in SectionII.B.6above, the question is whether the bid cap – regardless of

[70] Staff Addendum at 16.

purpose -- would have a direct impact on the operation of the wholesale market. Limiting DAM bids to $300/MWh in a FERC-regulated market with bid caps set at $2000/MWh can hardly help but have a direct impact on the price formation in that market. Thus, while some sort of bid cap on a capacity-based program may be the most viable answer to the Commission's concern, further analysis of the compatibility *overall* of the new framework with FERC jurisdiction should be considered.

3. The Bid Cap Proposal Adds Administrative Complexity

The Staff Addendum contemplates review by the ED of bids by RA counterparties into the CAISO markets. A failure of bidding within the price cap will cause the LSE buyers to be referred for RA non-compliance if "their" resources do not comply with this contractual provision.[71] This element of the proposal could be administratively burdensome, without automated tracking by CAISO. Worse yet, it places a burden on the LSE for its counterparty's non-performance. Under the current RA program, the resource owners shoulder the performance burden.

III. RESPONSE TO CAISO PROPOSALS

The CAISO advances six proposals, which largely would work within the existing capacity-based RA program structure.[72] Four of these proposals have been directed by the Administrative Law Judge to Track 3B.1.[73] CalCCA supports the remaining two recommendations under consideration in 3B.2: assessment of resources' unforced capacity (UCAP) and adoption of a multi-year system capacity requirements.

71 Staff Addendum at 18.

72 *Final Track 3.B. Proposals of the California Independent System Operator Corporation*, Dec. 18, 2020 (CAISO Proposals), at i.

73 *Email Ruling Regarding Track 3B.2 Proposals*, Jan. 11, 2021.

The CAISO proposes that the Commission's program rules reflect the same UCAP methodology the CAISO adopts in its Resource Adequacy Enhancements initiative.[74] The methodology will derive a net qualifying capacity (NQC) value by discounting a resource's deliverable QC "to account for recent historical unit forced and urgent outage rates during tight resource adequacy supply hours."[75] The Commission would work with the CAISO to set correct UCAP system requirement levels to ensure the resources procured under the Commission's program support the CAISO's reliability requirements.[76] CalCCA has supported the UCAP proposal in the CAISO stakeholder process and encourages alignment of Commission rules with this change.

The CAISO also proposes a multi-year system resource adequacy requirement for LSEs.[77] The requirement targets would be set as 100 percent for each of Years 1 and 2 and 80 percent for Year 3.[78] CalCCA does not oppose these targets in a capacity-based framework.

Finally, the CAISO concludes in its proposals that the "SCE-CalCCA proposal offers many positive elements, and the CAISO recommends the Commission and parties continue to vet, develop, and consider necessary and appropriate enhancements to the proposal for possible implementation in 2023."[79] The CAISO identifies several critical issues that need further discussion, including ensuring adequate capacity at the gross peak, the treatment of use- and availability-limited resources, and showing requirements and impacts on must-offer

74 *Ibid.*
75 CAISO Proposals at 24.
76 *Id.* at 29.
77 *Id.* at 31.
78 *Id.* at 32.
79 CAISO Proposals at 33.

obligations.[80] CalCCA agrees that these and other issues require further consideration and looks forward to additional workshops and comments to refine the proposal.

IV. RESPONSE TO PG&E PROPOSALS

PG&E offers two proposals – one aimed to address reliability and the other market price mitigation. Although the proposal remains conceptual, PG&E's "slice of day" reliability proposal could achieve many of the same objectives pursued by the SCE/CalCCA proposal. It would not, however, escape the challenges of the market price mitigation proposal that have been identified by stakeholders. Likewise, its market price mitigation proposal bears the same infirmities as other price control proposals with added complexity.

A. "Slice of Day" Proposal

PG&E's proposal is aimed at "meeting demand in all hours of the day with resources that are able to produce during particular hours and adequately adopting RA counting methodologies that accurately measure all resource contributions for being able to meet demand in the particular hours they are being relied upon to meet demand."[81] PG&E's contemplates seasonal compliance.[82] Within each season, showings would be made for each of several hourly slices of each day; PG&E proposes slices of 11pm to 7 am, 7 am to 3 pm, and 3 pm to 11 pm.[83]

The compliance value of each resource would be what the resource is capable of delivering during that slice of day period, based on an exceedance methodology for all technologies.[84] Since solar resources would primarily produce during the second "slice" their

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80 *Id.* at 34.
81 *Revised Track 3B.2. Proposals of Pacific Gas and Electric Company*, Dec. 18, 2020 (PG&E Proposals), Attachment 1 at A-3.
82 *Id.* at A-8.
83 *Id.* at A-4
84 *Id.* at A-5 – A-6.

value would be extremely limited during the third defined "slice."[85]. Storage and demand response (DR) should be able to show in any slice but charging to enable the contemplated storage discharge must be added to load in another slice. A gas-fired resource without use or availability limitations could be used for compliances in all slices of the day.

PG&E's thoughtful approach makes several key improvements on the existing system. The "slice of day proposal":

- ✓ Recognizes that time-dependent generation requires a system that accounts for reliability in all hours, and not just peak hours.
- ✓ Comes closer to technology neutrality because it recognizes that the contribution to reliability should reflect what resources are capable of delivering during each time period.
- ✓ Enables a portfolio with 100 percent renewables to be deemed adequate under this system, which is not true of the existing construct or the SFPFC proposal.
- ✓ Recognizes that load in different times of day can be met with entirely different sets of resources, unlike the MCC Bucket system, since there is no need for resources that meet load in all hours if a combination of resources can meet the same performance characteristics.

PG&E's proposal also reasonably addresses storage, recognizing that for storage to contribute to reliability, it is increasingly critical for the showing LSE to also identify the charging source for the storage. Simply relying on the market risks creating aggregate supply problems if the need for charging energy begins to exceed supply in some hours. Thus, LSEs showing storage for reliability in certain hours must identify a source for the energy to charge the storage going forward. Naturally, the power capacity used to charge storage would need to be accounted for in the RA requirements of the LSE in the hours when charging is occurring.

Despite these advances compared with today's framework, the PG&E proposal creates new issues. In general, its simplifications result in necessary imprecisions – for instance, solar

85 *Ibid.*

resources in the early evening may be assumed to be zero while still producing, gross- and net-peak appear undifferentiated, and extrapolating peak needs across many evening hours may unnecessarily exclude resources with availability limitations (e.g. storage, demand response). While it is possible that these may be addressed with refined slice-of-day windows or a more complex accounting scheme, these refinements could shift the proposal from "slice-of-day" to "hour-of-day," negating its simplicity benefits. These issues are worth exploring further to the extent the Commission moves forward in its assessment of the proposal.

For example, the proposal fails to:

- Capture the full value of solar generation when generation, depending on what time periods the slices are actually defined;
- Resolve the complexities of reflecting hydro generation availability; and
- Provide a solution for other use- or availability-limited resources including gas-fired resources.

Address temporal mismatches that arise within each slice. For example, solar value would be driven mostly by midday generation, but at the ends of the period, solar generation will be predictably lower than the exceedance value, creating the possibility of hourly mismatch. While PG&E's slice-of-day proposal attempts to bring valuable simplicity to a complex problem, a deeper analysis illustrates that this simplicity brings with it a bluntness which may lead to over-procurement, resource mis-valuation, and other issues. For example, it is unclear that the proposal adequately differentiates between peak and net-peak load, suggesting LSEs would be obligated to procure to the full need of the evening slice (gross peak) without being able to utilize solar resources. Similarly, it is unclear whether an 8-hour evening slice would need a corresponding set of resources capable of meeting peak demand for an 8-hour period. While these periods could be refined and narrowed, this would likely result in a construct more closely resembling an hourly obligation and would lose the appeal of simplicity. Similarly, variation in load, solar, and wind production between months complicates the aggregation of months into seasons while retaining accuracy.

While CalCCA continues to believe the SCE/CalCCA proposal addresses the same issues with less complexity, PG&E's proposal merits further consideration.

B. Contract Hedge Proposal

PG&E's contract hedge proposal "ties compensation for capacity to the unit's performance in the energy market, on an ex post basis."[86] The proposal requires RA suppliers to identify variable operating costs (or a proxy) in their RA contract and require a rebate of revenues in excess of those costs to the purchasing LSE whether or not the energy is actually sold into the market. The proposal aims to ensure that RA contracted resources bid energy into CAISO market in a way that does not drive up energy prices.

CalCCA appreciates PG&E's efforts to try to address ED's pricing and risk management concerns. Again, however, the proposal presents challenges. The variable operating cost approach works for thermal resources, effectively turning the contracts into the equivalent of a tolling agreement. It is unclear, however, how these costs would be set for non-thermal resources, particularly energy storage and demand response resources. In addition, the approach fails to recognize that the bid strategy by a supplier may have many more factors than variable operating costs, such as use limitations or other factors influencing a resource's opportunity cost. For example, the proposal could result in use-limited generators being required to provide rebates to their LSE counterparties for many hours in which the market cleared above their "marginal cost," despite that quantity of hours significantly exceeding the number of hours the

[86] PG&E Proposal at A-16.

resource could actually produce over the period. In short, determining the variable operating cost on a unit-by-unit basis presents significant complexity that may weigh against the proposal's benefits.

CalCCA acknowledges the Commission's continued desire to mitigate price risk in the energy market and PG&E's attempt to respond. For this reason, PG&E's proposal should be maintained for further consideration.

V. RESPONSE TO POWEREX PROPOSALS

A. Seasonal System RA Requirement

Powerex proposes modification of the Commission's RA program to require LSEs to meet RA requirements on a seasonal basis with a showing on a year-ahead basis.[87] Powerex reasons that this approach will "ensure that California LSEs are able to more effectively compete with external LSEs to obtain forward commitments of the physical supply necessary to meet reliability needs would align California's products more closely with other markets."[88] This modification to the current framework is unnecessary and works to the benefit of suppliers, not LSEs.

Powerex argues that this approach will avoid putting California LSEs "last in line" for regional resources, will reduce forecasting errors and the need to assess when precisely the summer load will peak, and allows California to benefit from regional diversity in peak load.[89] While this approach would benefit suppliers by reducing the risk that they will be able to sell supply for all months, it is unclear how it benefits LSEs and could lead to higher costs for

87 Powerex Comments at 2-3.
88 *Id.* at 2.
89 *Id.* at 2-3.

customers. If the only way for an LSE to obtain the supply it needs, it has the ability to contract for more than a single month; indeed, this occurs today.

B. Increased Penalties for RA Deficiencies

Powerex proposes an increase of penalties to reflect at least the full annualized Cost of New Entry.[90] CalCCA appreciates the problem Powerex aims to address: LSEs should not use non-compliance penalties as an alternative to RA compliance. Introducing an increased penalty structure, however, should not be adopted in a scarcity market *without* simultaneous adoption of a system RA penalty waiver framework that enables the Commission to better understand the reasons for non-compliance. Furthermore, increasing penalties will not result in greater reliability if the issue is a lack of supply which cannot be addressed in the short run. CalCCA continues to support adoption of a penalty waiver framework. Consequently, if the Commission intends to modify the penalties for non-compliance, a broader study should be taken to consider both the penalty level and a waiver framework.[91]

C. Assuring Imports Are Surplus to the Needs of the Source BAA

Powerex proposes a requirement for a representation that the physical generation capacity supporting an import RA contract is both surplus to the needs of the source BAA and has not been committed to any other BAA or LSE.[92] In principle, the proposal would not be objectionable if a resource owner can easily make this determination. It is not clear how a supplier, with the exception of a supplier affiliated with the balancing authority, is more likely to

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[90] Powerex Comments at 4-5.

[91] CalCCA offered a more detailed proposal through a Petition for Modification of D.19-06-026 and, at Staff's procedural recommendation, in Track 2 of this proceeding. *See generally California Community Choice Association's Late-Filed Track 2 Proposal*, Mar. 18, 2020.

[92] Powerex Comments at 5-6.

be able to meet this requirement. Powerex's proposal thus could reduce imports from other generators who do not have the advantage of controlling their own Balancing Authority.

VI. CONCLUSION

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

Respectfully submitted,

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