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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 Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON PROPOSED DECISION

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Pursuant to the Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA) submits these Comments on the November 21, 2018, Proposed Decision of Administrative Law Judges Allen and Chiv (PD) regarding Local Resource Adequacy (RA).

I. INTRODUCTION

Under the guise of local reliability, the PD resurrects the investor-owned utilities' (IOUs') 20th century role as central buyers (CB) of capacity and other attributes for all retail electricity customers, commandeering the statutory role of community choice aggregators (CCAs). The PD's "full procurement" central buyer framework (PD Framework), however, is a solution in search of a problem: there is no evidence of an urgent reliability problem. Even if the record supported the PD's premise, the PD Framework would be the wrong solution. There is no evidence that the IOU as CB can procure critical local RA resources at a price lower than the California Independent System Operator (CAISO) could achieve under its existing mechanisms. Moreover, the PD goes far beyond what would be necessary or reasonable to address a local reliability concern and is riddled with legal, policy and technical flaws. The PD can only be viewed as a transparent attempt, at customers' expense, to "put Humpty Dumpty back together again" and secure a larger role for the Commission in the rapidly evolving market.

As a foundational matter, the PD's draconian proposal reaches beyond the Commission's statutory authority and into the Federal Energy Regulatory Commission (FERC) wholesale capacity market jurisdiction. Rather than adopting a moderated "residual" approach, in which load-serving entities (LSEs) procure their own local RA and the CB acts only in the case of collective deficiency, the PD unnecessarily gives the IOUs "full procurement" authority. This approach markedly limits – if not defeats – participation by other LSEs in the wholesale local RA and potentially other wholesale markets. In addition, rather than focus narrowly on local RA, the purported driver for the multi-year mechanism, the PD requires bundling of local RA with other resource attributes for sale to the CB. In fact, the PD sets ***no limits*** to the products, commitment terms or quantities that may be procured by the IOUs under this mechanism. As a result, the PD dramatically reduces the scope and increases the risks of procurement by other LSEs, ignoring §380's[1] requirement to "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers."[2] Further, the extent of the PD's profound impacts on the operation of the wholesale capacity market moves the PD Framework over the boundary between state jurisdiction and the Federal Power Act.[3]

Not only is the PD Framework unlawful, it is bad policy. It will impair, if not eviscerate, the legislatively mandated CCA program, distort wholesale markets, increase rates and undermine climate goals. The PD will:

- Place a material portion of a non-utility LSE's portfolio out of its control, increasing risk and driving higher rates for its customers;
- Encourage over-procurement by the CB and all other LSEs, increasing rates for all retail customers;
- Devalue local RA under existing multi-year contracts, effectively abrogating those contracts;
- Create disincentives for LSEs to engage procurement of new renewable resources and Distributed Energy Resources (DERs), such as Distributed Generation (DG) coupled with Storage, Energy Efficiency (EE), and Demand Response (DR) in Local Capacity Areas (LCAs), thus hampering the LSE's efforts to support achievement of the state's climate goals.
- Shift costs among customers by failing to allocate costs in a manner that recognizes an LSE's measures to shape or reduce load.

The PD is a deeply flawed solution in search of a problem. On both legal and policy grounds, the Commission has little choice but to reject the PD and take the time needed to (1) identify and study any perceived reliability problem and (2) develop the least-restrictive solution that complies with state and federal law and minimizes harm to the state's market structure, climate change goals and rates.

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1 Cal. Pub. Util. Code §380. All further references to code sections will be references to the Public Utilities Code unless otherwise indicated.
2 Cal. Pub. Util. Code §380(a)(5); *see also* §380(h)(5).
3 16 U.S. Code §791a *et. seq.*

II. THE PD'S "FULL PROCUREMENT" CENTRAL BUYER FRAMEWORK UNDERMINES CALIFORNIA'S LEGISLATIVELY MANDATED MARKET STRUCTURE, IMPAIRS THE ACHIEVEMENT OF THE STATE'S CLIMATE GOALS AND INCREASES RATES

A. There Is No Evidence of a Local Reliability Crisis

The PD is based on an unsubstantiated conclusion that there is a local reliability problem that must be urgently solved. In fact, the PD contains no findings or conclusions regarding the existence or nature of any reliability problem. And to the extent the PD relies on conclusions in D.18-06-030, the Track 1 Decision, there was likewise no assessment of a reliability problem in Track 1. At best, the Track 1 Decision is rooted in anecdotal concern regarding procurement for 2018 under the CAISO Reliability Must Run (RMR) and Capacity Procurement Mechanism (CPM) tariffs.[4] In other words, ***this entire rulemaking is based on an undefined, unstudied and unsubstantiated problem***.

Further calling into question the basis for the PD's CB, the extent of CAISO backstop procurement mentioned in the Track 1 Decision has declined. The CAISO's review of 2019 RA sufficiency concludes that even without a formal multi-year RA program, there are no local RA collective deficiencies in the Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) service territories.[5] While there is a collective deficiency in the Pacific Gas and Electric Company (PG&E) service territory, it is limited to 219.73 MW – *only 2 percent* of the total required local RA.[6] In contrast, last year at this time the CAISO found a 1072 MW collective deficiency for PG&E,[7] 317 MW for SCE and 560 MW for SDG&E.[8] Moreover, 125 MW of the 220 MW shortfall is simply due to the fact that PG&E has failed to show Humboldt as a local RA resource in its year-ahead showing.[9]

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4 *See* D.18-06-030 at 26.

5 *Evaluation Report of Load Serving Entities' Compliance with 2019 Local and System Resource Adequacy Requirements*, Nov. 13, 2018 (2019 Evaluation Report) at 1. http://www.caiso.com/Documents/EvaluationReport_LoadServingEntitiesCompliance_2019Local_SystemResourceAdequacyRequirements.pdf

6 *Id.* at 2.

7 This shortfall is not surprising. *See* R.17-06-026, CONFIDENTIAL Exh. CalCCA-102-C at 5, n.6.

8 *Evaluation Report of Load Serving Entities' Compliance with 2018 Local and System Resource Adequacy Requirements*, Nov. 13, 2017, at 1-3. http://www.caiso.com/Documents/EvaluationReport_LoadServingEntitiesCompliance_2018Local_SystemResourceAdequacyRequirements.pdf

9 *See* 2019 Evaluation Report at 2 and Appendix A (showing remaining local need of 219.73 MW and 124.45 MW of remaining need in Humboldt (page 2), with over 160 MW of PG&E utility-owned generation in the Humboldt Area available and not shown (Appendix A)). *See also* R.17-06-026, CalCCA CONFIDENTIAL

The PD offers a solution for a problem that has not been identified. Even if the Commission believes a problem exists, the CB framework is akin to using a sledgehammer to crack a nut. The PD goes beyond all reasonable bounds.

B. The PD Abrogates Existing Multi-Year Local RA Contracts

The Track 1 Decision signaled to the market that the Commission was headed toward a multi-year, CB market structure for local RA that would be implemented for 2020.[10] LSEs have responded to the signals from the Track 1 Decision and the Energy Division by procuring multi-year RA resources. For example, PG&E issued a multi-year Request for Bids on March 15, 2018. Other generators and LSEs, including CalCCA members, have entered into bilateral RA agreements greater than one year.[11] It took only a statement of the Commission's intention to implement a multi-year program to get a market response. The PD penalizes responsive LSEs, however, by devaluing – effectively abrogating – the very multi-year contracts the Commission encouraged. In addition, the PD Framework violates §380(a)(5)'s requirement that the Commission "maximize" a CCA's ability to control its own RA procurement.

By making the IOU a "full procurement" CB, the PD Framework provides no credit to LSEs for existing multi-year contracts that provide local RA. The LSE can only gain credit or value for the local RA if the product is bundled with other RA attributes, offered in the CB's solicitation *and* selected for the CB's local RA portfolio. There is no guarantee, however, that the CB will procure the LSE's product; if it does not, the LSE has no other way to "count" or realize value for its existing local RA attributes. This framework not only abrogates the LSE's existing contracts, but dramatically increases the LSE's procurement risk, creating a high market entry barrier.

In addition, an LSE may not always be in a position to bid its local RA into the solicitation, due to the PD's requirement that all RA attributes from a resource must be bundled.[12] In order to monetize local RA from a resource, the LSE will be required to bid in all RA, including system and flexible RA. Depending upon market conditions and the sufficiency of the LSE's portfolio for other RA attributes, the LSE will be faced with the choice of monetizing the local RA and facing a deficiency in system or

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Exh. 102-C at 5, n. 6. It also warrants noting that RMR contracts increased only slightly in 2018 from 619 MW in 2013-2017 to 852 MW. CAISO, *Annual Report on Market Issues and Performance,* Department of Market Monitoring, 2012-2017; CAISO, *Q3 2018 Report on Market Issues and Performance,* Department of Market Monitoring, Nov. 1, 2018.

[10] D.18-06-030, Conclusion of Law 12, at 52.

[11] The Energy Division has the ability to view this change in market response to the Commission's multi-year RA signals through the contract data they receive directly from LSEs.

[12] *See* PD at 40.

flexible capacity[13] or simply holding onto the resource and its bundled RA attributes and sacrificing the value of local RA.[14] Moreover, even if the LSE elects to sell its bundled RA products, the PD fails to explain how the Least Cost Best Fit (LCBF) metric will value the attributes that are bundled with any sale of local RA[15] or value them in a way that adequately compensates the LSE.

By requiring "full" rather than "residual" procurement, and thus devaluing existing multi-year contracts, the PD violates §380(a)(5). The Commission is bound, in addressing reliability, to "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers."[16] Instead, the PD abrogates existing contracts and substantially reduces the scope of CCA procurement.

C. The PD's Proposed Framework Carries the Potential to Eviscerate the Legislatively Mandated CCA Program and Increase Rates for All Customers

The PD Framework is *not* a narrowly tailored solution to any identified problem and, consequently, does not maximize CCAs' ability to procure to meet its customers' needs. While the PD purports to address local reliability, its impact will extend to all dimensions of procurement, including other RA attributes, RPS resources and potentially energy procurement. Further, depending upon the IOUs' elections on contract term, these impacts may extend long beyond the three-year multi-year program. As a result, the PD Framework threatens to eviscerate the CCA program enacted by Assembly Bill (AB) 117, removing CCAs as partners in advancing achievement of the state's climate goals.

1. The Scope of Central Buyer Procurement is Unlimited

The PD strays far beyond the purpose of Track 2 by enabling procurement of any amount of any product for any duration. The purpose of Track 2 is narrowly defined as "determining the implementation requirements for a multi-year and central procurement of *local RA* capacity."[17] And

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[13] While the central buyer will allocate any flexible RA procured to all LSEs, the capacity will be allocated based on load share, and an LSE selling a resource with flexible RA into the solicitation will receive only a very small allocation of the RA it sells.

[14] The PD fails to consider the consequences of an LSE declining to bid an essential into the solicitation in order to meet the LSE's system or flexible RA requirements. Because the central buyer is a "full procurement" entity, it will not (and should not) be permitted to count the local RA for a resource retained by an LSE.

[15] Today, the LCBF metric is used in the IOUs' bundled procurement process. It is unclear how the IOU can determine the "best fit" for numerous LSE portfolios in its solicitation.

[16] Cal. Pub. Util. Code §380(a)(5); *see also* §380(h)(5).

[17] Proposed Decision at 4.

while the Commission has signaled its intent to take the CB concept beyond local RA,[18] there is ***no record*** to inform this aggressive approach.

The Proposed Decision orders the CB to "engage in full procurement of local resources within their respective distribution service areas."[19] Notably, the directive is not limited to local ***RA*** products, but local ***resources***. This characterization, used throughout the PD, suggests the IOU could procure, for example, a new renewable energy project in an LCA with all attributes. Reinforcing this conclusion, the PD requires expressly that "RA attributes shall remain bundled" and provides for an allocation among LSEs of any system or flexible RA that is bundled with the local RA.[20] Likewise, the PD contemplates inclusion of dispatch rights in the CB solicitation, which implies that energy may also be procured.[21]

The PD Framework lacks other critical limitations. The PD does not define "local resources" – the designated scope of procurement. Presumably, the PD means to cover any resources located in an LCA, but the limitation on the scope of resources is unclear. Likewise, the PD fails to limit contract term. While the PD adopts a three-year forward framework, it also "encourage[s] the central buyers to enter into longer-term contracts if it is in ratepayers' interest to do so."[22] The lack of term limitation is particularly striking in the face of the PD's express acknowledgement that a shorter duration mitigates the risk of over-procurement.[23] Finally, the PD fails to place any limit on the amount of resources that may be procured. It states:

> As with the three-year forward duration, the Commission's adopted percentages of 100% for Years 1 and 2 and 80% in Year 3 are minimum requirements. The minimum percentages do not preclude the CBs from exceeding those percentages and ***we encourage the central buyers to do so*** if it is in ratepayers' interest.[24]

In this way, the PD is internally inconsistent, [25] simultaneously encouraging over-procurement while expressing concern about the cost of over-procurement to customers.[26]

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18 *See generally* Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability, R.16-02-007, issued Nov. 16, 2018.
19 Proposed Decision, Ordering ¶2 at 69.
20 *Id*. at 37.
21 *Id*., Ordering ¶9 at 70.
22 *Id*. at 25.
23 *Id*.
24 *Id*. at 30 (emphasis added).
25 It is important in this context to understand that the PCIA decision, D.18-10-019, places a value of zero on any RA capacity in excess of utility LSE needs. *See* D.18-10-019 at 73.
26 PD at 25, 30. The PD brushes the problem aside, concluding that bundled system or flexible capacity value acquired with the local RA can mitigate over-procurement costs. This conclusion is without record support and cannot be drawn without a broader examination of the impact of broad central procurement. It also bears

The PD places virtually no limitations on CB procurement – not on the scope of resource or products, term, or amount. Without these limitations, the PD Framework threatens the very existence of CCAs, as discussed below, and increases the costs to all ratepayers. The unbridled encouragement of IOUs as CBs to "corner" the market will also affect other market participants, including publicly owned utilities outside of the scope of Commission jurisdiction but within the CAISO control area – a point the PD overlooks.

2. The PD Framework Threatens Stable, Reasonable Rates

The broad scope of procurement authority contemplated by the PD will affect the prices LSEs pay for local RA, reverberating in their customers' pocketbooks. The CB will allocate local, flexible, and system RA and associated costs to LSEs' customers without the input of the serving LSE.[27] While the scope of procurement suggests that there will also be energy and renewable energy credits (RECs) at issue, the PD provides no discussion of how these products and their costs will be allocated. Placing a potentially significant portion of a non-utility LSE's portfolio and costs outside of that LSE's control and, worse yet, in the hands of its competitor, complicates risk management and will drive higher costs.

The risk of higher costs is exacerbated by the PD's encouragement of over-procurement —[28] a directive that runs contrary to the intent expressed in D.18-06-030 to avoid "saddling" customers with excess capacity.[29] Over-procurement by the CB puts each non-utility LSE at risk for over-procurement and unnecessary costs. As noted above, LSEs will have little insight in advance of the extent to which the CB will resource what should rightfully be the LSE's generation-side portfolio with products *beyond* local RA. As a result, the LSE has the choice of (1) leaving ample room in its portfolio to accommodate unexpected volumes of system or flexible RA allocated by the CB or (2) procuring system and flexible RA more aggressively, risking over-procurement and the associated excess costs. Either approach will increase the costs of an LSE's portfolio and drive higher rates for its customers.

Finally, the economic inefficiency of the PD Framework adds costs to the collective local RA procurement cost. Assume that a generator sells a resource with a local RA attribute to an LSE. To retain the value, the LSE must bid all RA attributes for the resource into the CB solicitation. If the bid is accepted, the CB will add to the procurement cost its administrative and financing costs, and then re-

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consideration that the PCIA decision, D.18-10-019, places a value of zero on any RA capacity in excess of utility LSE needs.

27 PD at 55.

28 PD at 30.

29 D.18-06-030 at 16.

allocate the attributes and new costs back to all retail customers. The collective market will be in no different position than it would have been if the LSE had simply been allowed to claim credit for the original contract, but the cost of the same capacity will be higher due to the administrative costs. If the original contract was a sale by the IOU to an LSE, the process is even more absurd, as the IOU would buy back the capacity it sold to the LSE and allocate it back to the LSEs' customers at a higher cost. This unnecessary stream of transactions and costs contributes to unjust and unreasonable rates for local RA capacity and contributes further to the crisis of affordability in IOU rates.

3. The PD Framework Threatens CCAs' Role as a Partner in Advancing the State's Climate Goals

As a result of their close relationship to local government, CCAs are inherently positioned to advance the achievement of the state's climate goals with action at the local level. To date, CCA programs have contracted for more than 2,200 Megawatts (MW) of new clean generation capacity, largely through power purchase agreements with terms of 10 years or more. CCAs also have signed contracts for a combined total of 90 MW/360 Megawatt hours (MWh) of battery energy storage, coupled with a combined 328 MW of solar. Many of the projects providing climate benefits require revenue streams from the sale of both energy and capacity products. The PD Framework thus threatens continuing progress by CCAs in their role as a climate change partners, by making it too risky for CCAs to invest in local RA altogether and thus undermining CCA investment in solar plus storage by taking away a key incentive. It further undermines their ability to meet the requirements of Public Utilities Code §399.13, which requires CCAs to meet at least 65 percent of their RPS obligation with contracts of more than 10 years by 2021.

The "full procurement" framework, where the CB procures the entire amount of required local RA bundled with other attributes, creates a procurement quandary for an LSE. Assuming a local RA premium, the LSE has two choices: (1) procure a local project and take the risk that it will be able to monetize the local RA value in the market or (2) not pay for any local RA premiums.

- Economic incentives will drive the LSE to pay a premium for local RA value only when it believes monetization is relatively certain. Yet even if recovery were certain, the LSE may need the associated system and/or flexible capacity bundled with the local RA, as discussed in Section II.C.1, and thus would not be in a position to sell the local resource into the solicitation.

- If the LSE takes the second, more likely route, it will not pay for local RA value in resourcing its portfolio to avoid market risk. Under circumstances where there is a market premium for local RA, this means a new resource will be inclined to sell to the bidder who will compensate for a local RA premium – the CB. In other words, the CB's local RA procurement could interfere with an LSE's ability to procure any new resource in LCAs.

The RA Framework thus creates barriers to procurement of resources in an LCA by favoring the CB over CCAs. This strong bias thus reduces the capability of an LSE to go beyond statutory requirements to support achieving the state's climate goals.

III. THE PD FRAMEWORK IS UNLAWFUL

A. The PD Framework Violates State Law

The PD Framework violates §366.2(a)(5), which provides:

> A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.

Central buyer "full procurement" on behalf of all LSEs has never been expressly authorized by the Legislature, and the Commission has no legal authority to adopt the PD Framework. "Administrative regulations that alter or amend the statute or enlarge or impair its scope are void and courts not only may, but it is their obligation to strike down such regulations."[30]

Even if the authority provided in subdivision (h) of §380, to "consider" a central procurement mechanism, were somehow stretched to find implicit authority, such authority would not be unbounded. The Legislature set clear and emphatic boundaries on the Commission's design of *any* RA program to prevent the Commission's encroachment on CCA procurement autonomy. Section 380(a)(5) requires the Commission to "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers." The statute repeats this directive in subdivision (h)(5), requiring the Commission to ensure that "community choice aggregators can determine the generation resources used to serve their customers." Several less restrictive approaches have been proposed in this proceeding, such as a residual central buying approach, that present a higher likelihood of meeting this clear standard, but are rejected by the PD as infeasible due to the alleged urgency for implementation.

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30 *San Francisco Fire Fighters Local 798 v. City & Cnty of San Francisco* (2006) 38 Cal.4th 653, 668.

B. The PD Framework Is Preempted by the Federal Power Act

Wholesale capacity markets fall squarely within FERC jurisdiction under the Federal Power Act.[31] This jurisdiction extends to "classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications or services."[32] The PD's "full procurement" CB approach for bundled RA attributes usurps FERC's regulation of the wholesale local RA market and profoundly affects the market for other RA attributes and LSEs not under the Commission's jurisdiction. The PD unabashedly oversteps the boundary between state and federal jurisdiction, and its proposed framework is preempted by the Federal Power Act.

The CB's procurement and "allocation" to LSEs are wholesale transactions, despite the PD's attempt to turn a blind eye. IOUs have no express or implied legal authority to procure generation on behalf of other LSEs' customers, as discussed in Section III.A. Moreover, §380 places the obligation to procure RA in the wholesale market on the LSE, not the LSE's customer.[33] Finally, the CB will allocate the RA capacity directly to LSEs, not their customers.[34] In other words, when the IOU as CB procures RA, it actually "sells" the RA to the LSE, *not* to the LSE's customers; the transaction thus is a sale for resale subject to FERC jurisdiction.[35] That the charge is buried in a customer distribution rate is only an accounting fiction. The PD Framework thus contemplates Commission design and operation of a centralized wholesale capacity market, including oversight of price formation – an action that is preempted by federal law.

Even if the PD Framework were not a direct affront to FERC jurisdiction, it profoundly interferes with the operation of the wholesale capacity market in several other ways. The "full procurement" framework:

- Reduces the number of buyers in the local RA market from many to one in each IOU area, by discouraging non-IOU LSE participation.[36]

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[31] 16 U.S.C. §824(b)(1). The Federal Power Act confers on FERC jurisdiction over the "sale of electric energy at wholesale in interstate commerce."
[32] 16 U.S.C. §824d.
[33] Cal. Pub. Util. Code §380(c)("Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements.").
[34] PD at 55.
[35] The PD's attempt to mask the wholesale nature of the transaction between the central buyer and LSE behind the Cost Allocation Mechanism (CAM) does not cure the lack of legal authority for the PD Framework.
[36] *See* Section II.C.3, *supra* at 8-9.

- Reduces the ability of LSEs to anticipate their system and flexible RA needs due to the CB's unpredictable procurement on their behalf, making it more likely that they either fail to meet their RA requirements or unnecessarily increase rates to cover the costs of over-procurement.

- Increases the collective cost of meeting RA requirements without adding value, by adding to the complexity of transactions[37] and encouraging collective over-procurement. [38]

Moreover, the RA Framework impairs the wholesale RA markets in these ways *without* a finding that the action is necessary to address a bona fide reliability problem or that the solution is the least restrictive means of addressing the problem.

The Commission cannot rely on FERC's continued accommodation of the state's role in coordinating resource adequacy with the CAISO. Less than a month ago, in *La Paloma*, FERC found that "this bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy."[39] Yet FERC is aware that circumstances could change "such that this division of responsibilities has become unjust and unreasonable."[40] FERC has found that the division of responsibilities becomes "unjust and unreasonable" when "one party's resource adequacy decisions can cause adverse reliability and cost impacts on other participants in a regionally operated system."[41] Moreover, the Supreme Court of the United States has found that measures aimed to implement state electricity policy are permitted only to the extent they are "untethered" to wholesale market participation.[42]

The CB's decisions will have cost impacts, as explained above, on all LSEs in the CAISO region. In addition, the PD Framework is tethered directly to participation by the CB and other LSEs in the wholesale capacity market. The PD Framework thus exceeds the Commission's authority and is preempted by federal law.

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37 *See* Section II.C.2, *supra* at 7-8.

38 *See* Section II.C.2, *supra* at 7.

39 165 FERC ¶ 61,148 at P29

40 *Id*.

41 116 FERC ¶ 61,274 at P 1113, *citing Calif. Indep. Sys. Operator*, 115 FERC ¶ 61,172, at P 36 (2006) (CAISO II), Gainesville Utils. Dep't v. Fla. Power Corp., 402 U.S. 515, 529 (1971) (Commission has the "responsibility to the public to assure reliable efficient electric service").

42 *See Hughes v. Talen Energy Mktg., LLC,* 136 S.Ct. 1288, 1299 (2016)(concluding that states may encourage new or clean generation "through measures 'untethered to a generator's wholesale market participation.'").

IV. RECOVERING RA COSTS THROUGH DISTRIBUTION CHARGES CREATES DISINCENTIVES TO DEPLOY DR AND EE MEASURES AND SHIFTS COSTS AMONG CUSTOMERS

The PD proposes to use the CAM as "the cost recovery mechanism to [re]cover procurement costs associated with serving the central procurement function."[43] CAM cost recovery ignores long-standing principles of cost causation, undermines EE and DR incentives and shifts costs among customers of different LSEs.

Allocating the costs of the multi-year program using CAM ignores cost causation by failing to account for the load shape and load management tools used by an LSE to serve its customers. CAM capacity is allocated to LSEs based on their year-ahead load forecast of coincident peak load shares, tailoring the capacity allocation to each LSE's particular load shape. CAM costs, however, are allocated by customer class[44] through the New System Generation Charge (NSGC), which is bundled with distribution charges for bill presentation.[45] As a result, a bundled residential customer will pay the same rate as a residential CCA customer.

By equalizing rates, CAM cost recovery devalues an LSE's individual expenditures to reduce its load share. Today, if an LSE invests in DERs, such as EE or DR, it can reduce its peak load and its overall local RA obligation. By reducing its overall RA obligation, the LSE is required to procure less RA, which is how it "monetizes" its investment in the DERs. By monetizing its investment, the LSE can maintain its competitiveness because its costs (the DER investment + reduced local RA cost) are matched with its revenues recovered through its customers' rates. The current methodology thus fairly reflects cost-causation principles and sends the right signals to invest in emissions-reducing investments. In contrast, the CAM allocation methodology, which will be broadly applied if the PD is adopted, removes these incentives. Reductions in the LSE's RA need are credited to *all* LSEs' customers, not specifically to that particular LSE's customers, shifting costs among customers.

The Commission's policies and rates should be designed in a way that ***encourages*** DERs. Instead, the PD Framework will sweep evermore attributes into the CAM recovery mechanism, shifting costs among LSEs and diluting an LSE's financial ability to pursue these measures. Not only does this approach fail to reflect cost causation, it removes additional service elements from the scope of price

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[43] PD, Conclusion of Law 14 at 67.

[44] *See, e.g.,* PG&E Tariff Schedule A-1, Sheet 4.

[45] Based on a review of General Rate Case Phase II filings and workpapers back to 2011 for SCE and PG&E, it appears that PG&E uses an equal cents per kilowatt-hour methodology, and SCE uses a 12-CP methodology.

competition among LSEs. The CAM cost-recovery mechanism is the wrong methodology to allocate ***any*** RA attributes, and particularly the additional attributes added to the mix by the PD Framework. If, in fact, any form of central buying can be legitimized, it must be recognized as a wholesale transaction, with costs allocated to LSEs rather than their customers.

V. THE PD DOES NOT ADDRESS THE IOUS' CONFLICTS OF INTEREST

To any commercial entity outside of the arcane energy regulatory sphere, the PD's Framework would appear incredible, tilted wildly in favor of the incumbent and against its competitors. The framework places one competitor, the incumbent utility, in the position of buying products for not only its customers, but all of its competitors' customers. The competitors have no control over the resources procured or the cost of those resources and must try to manage their portfolio risk with virtually no insight into the incumbent's activities. The incumbent gains a wide range of valuable market information and dispatch control over resources through its CB role, which is unavailable to its competitors. Finally, the costs incurred by the incumbent will be fully socialized, allocated to each competitor's customers regardless of the efficiency or effectiveness of each competitor's market and load-management strategy. The IOUs are highly advantaged relative to their competitors.

Other advantages will flow from the IOUs' multiple market roles. For example, PG&E sells RA using generic contracts under which it can later designate the resource meeting its obligation. If this practice continues, two problems will arise. LSEs procuring generic RA from PG&E will not have the information necessary to participate in the CB solicitation in a timely manner.[46] Even if they did, PG&E will be in a position to choose units of lesser value to support existing seller's choice contracts, holding more valuable units for sale by PG&E to itself in the CB solicitation.

The PD declines to adopt measures to prevent the IOUs from being advantaged by their multi-dimensional position as the primary holder of resource adequacy products, central buyer, retail service provider and transmission provider. Not to worry, however, there will be rules to prevent any conflict of interest – which the incumbent itself will propose[47] – and a portfolio approval process will be considered later in the proceeding.[48] In addition, procurement will be overseen by "independent" evaluators chosen

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[46] Section 2.2 of PG&E's Standard Confirm for RA sales requires PG&E to identify the unit "no later than fifteen (15) Business Days before the relevant deadlines for the corresponding Compliance Showings applicable to the relevant Showing Month." https://www.pge.com/en_US/for-our-business-partners/floating-pages/2017-resource-adequacy-request-for-offers-rfo/2017-resource-adequacy-request-for-offers-rfo.page

[47] PD, Ordering ¶ 17 at 73.

[48] *Id.*, Ordering ¶ 15 at 72.

– and presumably paid – by the IOUs. If the Commission wishes to place the market at risk, as the PD Framework does, market participants deserve an explanation of how the Commission will constrain the advantages it confers on the IOUs.

VI. OTHER ISSUES

A. Timing

The proposed schedule provides insufficient time for LSEs to integrate CB procurement with the remainder of their portfolios, particularly given the potentially broad scope of that procurement. From July to September, the CB runs a solicitation for all local areas. In late September, CBs make a showing of all attributes procured, including local RA, to the Commission and the CAISO. In late September/early October, LSEs are allocated final CAM credits (based on coincident load shares) for any system and flexible capacity that was procured during the local RA procurement or backstop processes. *LSEs have less than one month to adapt their portfolios to integrate the central buyer procurement before being required to make their showing in the end of October 2019*! The PD Framework likewise creates an unrealistic expectation for the CBs, requiring them to run and conclude solicitations for "full procurement" of all local RA resources and document the resulting transactions within three months. Apart from the myriad other problems with the PD Framework, the schedule it proposes is untenable.

B. Power Charge Indifference Adjustment Interactions

To the extent not otherwise included in the CAM, most local RA resources are held by the IOUs in their PCIA-eligible portfolios. Consequently, RA sales by the IOUs through the solicitation will interact with PCIA rates in ways that have not yet been explored. For example, while the PD requires IOU resources that are bid into the solicitation to be bid at their "levelized fixed costs,"[49] it is less clear about whether the resources are *required to bid* at all. It is also not clear how these rules will interact with the requirement of D.18-10-019 that RA forecast to be "unsold" will be valued at zero in the PCIA benchmark.[50] Finally, the PD fails to consider how the PCIA interactions with the multi-year program will affect bid behavior, PCIA rates and potential cost shifts. With the ink on D.18-10-019 barely dry and the new PCIA yet to be implemented, the Commission should be cautious in adopting changes that will have unanticipated and unintended consequences on the PCIA.

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[49] PD, Ordering ¶ 7(e).

[50] D.18-10-019, Ordering ¶ 1.c at 159-160.

C. PG&E's Financial Condition

The IOUs face significant financial impacts as a result of the California wildfire crisis. On November 13, 2018, PG&E filed an 8-K report with the Securities and Exchange Commission disclosing it has withdrawn all of the cash available from its revolving credit lines, which could be viewed as a step toward bankruptcy. On November 15, Moody's downgraded PG&E's long-term ratings, including its senior unsecured rating to Baa2 from Baa1, and further downgrades could occur. On November 28, PG&E filed an application for authority for up to $6 billion in short-term borrowing to "provide flexibility for PG&E to meet potentially higher collateral posting requirements associated with PG&E's energy procurement activities…."[51]

PG&E is not alone in this downward financial spiral, with SCE experiencing credit downgrades in September.[52] Under these circumstances, imposing additional procurement obligations on the IOUs is ill-advised.

VII. CONCLUSION

The PD Framework violates existing law and sets bad policy. Under these circumstances, the Commission should reject the PD and, instead, take deliberate steps to identify and study any perceived reliability problems and design a well-tailored solution that will "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers"[53] as required by state law.

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Respectfully submitted,

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[51] *Application For Authority to Issue Up to $6,000,000,000 To Finance Its Short-Term Borrowing Needs and Procurement-Related Collateral Costs, A.18-10-003.*

[52] https://www.moodys.com/research/Moodys-downgrades-Southern-California-Edison-to-A3-from-A2-and--PR_388504 On December 3, Moody's revised SCE's ratings outlook from "stable" to "negative." https://www.moodys.com/research/Moodys-revises-the-ratings-outlook-of-Southern-California-Edison-and--PR_392015

[53] Cal. Pub. Util. Code §380(a)(5); *see also* §380(h)(5).