

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

Joint Application to Establish Non-Bypassable
Charge (“NBC”) for Above-Market Costs
Associated with Tree Mortality Power Purchase
Agreements (“Tree Mortality”) in Compliance with
Senate Bill 859 and Resolution E-4805.

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Application No. 16-11-005
(Filed November 14, 2016)

**COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE ENERGY DIVISION STAFF PROPOSAL**

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May 11, 2018

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

Joint Application to Establish Non-Bypassable Charge)	
("NBC") for Above-Market Costs Associated with Tree)	
Mortality Power Purchase Agreements ("Tree)	Application No. 16-11-005
Mortality") in Compliance with Senate Bill 859 and)	(Filed November 14, 2016)
Resolution E-4805.)	
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**COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE ENERGY DIVISION STAFF PROPOSAL**

In accordance with the *Administrative Law Judge's Ruling Entering Energy Division Staff Proposal Into The Record And Seeking Party Comments*, dated April 17, 2018 ("ALJ Ruling"), the California Community Choice Association ("CalCCA") hereby provides comments on the Energy Division staff proposal, attached as Appendix A to the ALJ Ruling ("Staff Proposal"), and responses to specific questions pertaining to the Staff Proposal.¹

I. SUMMARY

As reflected in Appendix B to the ALJ Ruling, CalCCA made a presentation at the December 12, 2017 workshop ("Workshop") regarding how above-market costs of the investor-owned utilities' ("IOUs") Tree Mortality power purchase agreements ("BioRAM PPAs") should be determined and allocated to customers. The IOUs also made a presentation at the Workshop on the same topic. In its presentation, CalCCA stressed the importance of ensuring that mandated procurement directed by the California Public Utilities Commission ("Commission") should not unnecessarily infringe on the statutory right of Community Choice Aggregators to procure generation resources on behalf of Community Choice Aggregation ("CCA") customers. CalCCA also urged the Commission to not

¹ See Staff Proposal at 3.

reinvent the wheel, so to speak, with respect to determining above-market costs for the BioRAM PPAs, but instead the Commission should rely on methodologies and processes closely aligned with the Commission's principal non-bypassable charge ("NBC"): the Power Charge Indifference Adjustment ("PCIA").²

For reasons stated in the Staff Proposal, the BioRAM NBC in the Staff Proposal does not rely on benchmarks and processes associated with the PCIA. CalCCA believes this departure is not ideal. However, given the limited duration and scope of the BioRAM NBC, CalCCA acknowledges the rationale set forth in the Staff Proposal. That said, further investigation appears to be necessary to determine whether there is or will be a sufficiently deep pool of power purchase agreements to validate the benchmark under the Staff Proposal. As currently written, the benchmark is "the average price of [Renewables Portfolio Standard ("RPS")] procurement from non- BioRAM PPAs that were signed in 2016, which is the contemporaneous year for all BioRAM [PPA] execution."³ It is CalCCA's understanding that only one non-BioRAM PPA signed in 2016 ("Reference PPAs") has commenced energy deliveries, and only recently. As such, balancing account treatment may be warranted until the Energy Division feels confident that energy actually delivered from Reference PPAs is sufficient to validate the benchmark for valuation purposes under the Staff Proposal.

CalCCA also requests that the Energy Division conduct further analysis to ensure that costs under the Reference PPAs are reasonably comparable in form to costs expected under the BioRAM PPAs. In this regard, CalCCA notes that the BioRAM PPAs are associated with baseload-operated resources whereas resources associated with the Reference PPAs appear to be exclusively solar

² The Commission is actively reviewing and considering alternatives to the PCIA in an ongoing rulemaking proceeding: R.17-06-026.

photovoltaic (“PV”) resources, which operate on a non-baseload basis and could have a different cost structure. Finally, while CalCCA acknowledges the rationale for using a methodology that differs from the PCIA, CalCCA requests that the Energy Division reexamine this determination after the PCIA has been revised or replaced, later this year.

II. RESPONSES TO SPECIFIED QUESTIONS

As stated in the ALJ Ruling, “[t]he staff proposal includes specific questions for the parties to address in their comments.”⁴ The following are CalCCA’s responses to the specific questions in the Staff Proposal.⁵

1. **Does the staff proposal have any inaccuracies or inconsistencies with Commission policies and RPS rules? If so, explain your response.**

No.

2. **Is there sufficient transparency for the resulting non- BioRAM average contract benchmark, given that some of the individual contracts used to determine the average price will be confidential?**

CalCCA believes that Energy Division staff will have sufficient visibility of the Reference PPAs to review the Reference PPAs and identify costs under the Reference PPAs. To improve transparency, however, CalCCA recommends that, as part of a final decision in this proceeding, the Commission approve and adopt the modified non-disclosure agreement and data-sharing proposals approved in R.17-06-026 (PCIA rulemaking). In doing so, the Commission will ensure that employees of Community Choice Aggregators will have greater access to underlying PPA data than would otherwise be provided

³ See Staff Proposal at 2. As noted in the Staff Proposal, the scope “[i]ncludes RPS PPAs from solicitations that were executed in 2016, but excludes Qualifying Facilities (QFs) and Feed- in Tariff (FiT) programs such as BioMAT and ReMAT.” (Staff Proposal at 2; note 2.)

⁴ ALJ Ruling at 2

⁵ See Staff Proposal at 3.

under the Commission’s standard non-disclosure agreement.⁶ This action will improve transparency and is appropriate given the Energy Division’s reliance on actual costs to validate the benchmark for the BioRAM NBC.

CalCCA further recommends that, prior to applying the BioRAM NBC, the Energy Division should ensure that there is a sufficiently deep pool of Reference PPAs (more specifically, energy delivered under the Reference PPAs) to allow for a credible determination of the benchmark. CalCCA is further reviewing information provided by the IOUs, but on initial review it appears that only one of the Reference PPAs has begun delivering energy, and only recently. As such, it will likely be necessary to continue balancing account treatment until the Energy Division feels confident that energy actually delivered from Reference PPAs is sufficient to validate the benchmark for valuation purposes under the Staff Proposal.

CalCCA also requests that the Energy Division conduct further analysis to confirm that costs under the Reference PPAs are reasonably comparable in form to costs expected under the BioRAM PPAs. The BioRAM PPAs are associated with baseload-operated resources, and it appears that resources associated with the Reference PPAs are exclusively solar PV resources. As a result, the form of costs incurred for the Reference PPAs could deviate materially from expected the form of costs associated with the BioRAM PPAs. If this were to occur, a different benchmark should be considered.

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⁶ See *Assigned Commissioner and Assigned Administrative Law Judge Ruling Granting Relief Sought in December 8, 2017 Supplemental Joint Report on Data Issues*, dated December 20, 2017, in R.17-06-026.

3. **In the staff proposal, the [Renewable Energy Credits (“RECs”)] would be retained by the IOUs. The staff proposal also does not apply a separate valuation for RECs. Do you agree or disagree on how staff’s REC value is determined? Explain why or why not. If an alternative REC value is recommended, explain how the alternative is consistent with RPS rules, such as portfolio content classification rules.**

As stated in CalCCA’s Workshop presentation, CalCCA believes that RECs associated with the BioRAM PPAs should be retained by the IOUs, which is consistent with the Staff Proposal. However, CalCCA believes that the RECs should be separately valued using the valuation methodology under the current PCIA methodology, to be revised or replaced in the PCIA rulemaking.⁷ CalCCA believes that this approach best ensures consistency among NBC methodologies, and relies on findings and determinations previously made in the context of the PCIA (and on findings and determination subsequently made in the context of the PCIA rulemaking). That said, CalCCA acknowledges the rationale for using the integrated benchmark proposed in the Staff Proposal for the limited purpose of valuing above-market costs of the BioRAM PPAs.

4. **In the staff proposal, the [Resource Adequacy (“RA”)] would be retained by the IOUs. Explain why or why not staff’s proposal is consistent with RPS rules. If an alternative allocation is recommended, explain how the alternative is consistent with RPS rules and CPUC policies.**

As stated in CalCCA’s Workshop presentation, CalCCA believes that RA associated with the BioRAM PPAs should be retained by the IOUs, which is consistent with the Staff Proposal. However, CalCCA believes that the RA value should be separately established using the valuation methodology under the current PCIA methodology, to be revised or replaced in the PCIA rulemaking.⁸ CalCCA believes that this approach best ensures consistency among NBC methodologies, and relies on findings and determinations previously made in the context of the PCIA (and on findings and determination subsequently made in the context of the ongoing PCIA rulemaking). That said, CalCCA acknowledges

⁷ See Staff Proposal; Appendix B (CalCCA Presentation at 7).

⁸ See Staff Proposal; Appendix B (CalCCA Presentation at 6).

the rationale for using the integrated benchmark proposed in the Staff Proposal for the limited purpose of valuing above-market costs of the BioRAM PPAs.

- 5. Given staff's rationale that the methodology should be consistent with RPS rules, the proposal is different than the current PCIA methodology. Explain any consequences or benefits of having different methodologies or the same methodologies.**

As stated above, CalCCA acknowledges the rationale for using the integrated benchmark proposed in the Staff Proposal for the limited purpose of valuing above-market costs of the BioRAM PPAs. The overall cost and expected duration of the BioRAM PPAs are limited and circumscribed. That said, CalCCA believes that a valuation methodology using inputs from the PCIA methodology, to be revised or replaced in the PCIA rulemaking, would best ensure consistency among NBC methodologies, and would rely on findings and determinations previously made in the context of the PCIA (and on findings and determination subsequently made in the context of the PCIA rulemaking). As such, CalCCA requests that the Energy Division reexamine the BioRAM NBC benchmark after the PCIA has been revised or replaced, later this year.

III. CONCLUSION

CalCCA thanks the Commission for their consideration of these comments.

Dated: May 11, 2018

Respectfully submitted,

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**REPLY COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

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May 18, 2018

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Joint Application to Establish Non-Bypassable Charge)
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**REPLY COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

In accordance with the *Administrative Law Judge’s Ruling Entering Energy Division Staff Proposal Into The Record And Seeking Party Comments*, dated April 17, 2018 (“ALJ Ruling”), the California Community Choice Association (“CalCCA”) hereby provides these reply comments on matters addressed by the Office of Ratepayer Advocates (“ORA”) and the joint investor-owned utilities (“Joint IOUs”) in their opening comments on the Energy Division staff proposal, attached as Appendix A to the ALJ Ruling (“Staff Proposal”).¹

I. REPLY

A. CalCCA Appreciates And Supports ORA’s Requests For Clarification.

In its opening comments, ORA seeks clarification of two matters in order to promote transparency. First, ORA states that the Staff Proposal is unclear as to whether “an average contract *price* (\$50 per megawatt [(“MW”)] hour, for example) versus average contract *total costs* (\$50 per megawatt hour multiplied by the generation amounts for a period, month, year, etc.) will be used as the benchmark.”² In this regard, ORA explains that “further explanation for how the [2016] non-BioRAM average contract [(“Reference PPAs”)] benchmark will be calculated will serve to increase

¹ The Joint IOUs consist of Pacific Gas and Electric Company (“PG&E”), San Diego Gas & Electric Company (“SDG&E”), and Southern California Edison Company (“SCE”).

transparency.”³ CalCCA agrees, and appreciates ORA’s request for clarification. For additional reasons described below, CalCCA believes that the Staff Proposal should be expanded from simply a narrative description to also include quantitative examples.

Second, ORA seeks clarification that, “although the cost data gathered from [the Reference PPAs] will be confidential...Energy Division will be responsible for compiling this information and calculating the benchmark [and that] the final benchmark figure representing the [Reference PPAs] will be public.”⁴ Again, CalCCA agrees, and appreciates ORA’s request for clarification. For transparency sake, it will be important for the Energy Division to maintain a central role, and for the benchmark for the IOUs’ Tree Mortality power purchase agreements (“BioRAM PPAs”) to be publicly reviewable.

B. The Joint IOUs’ Proposal To Allocate Renewable Energy Credits Implicates A Host Of Policy And Legal Issues, And Is Ill-Suited For This Proceeding.

In their opening comments, the Joint IOUs repeatedly promote the *allocation* of Renewable Energy Credits (“RECs”) from the BioRAM PPAs as a superior means of determining the Tree Mortality non-bypassable charge (“Tree Mortality NBC”).⁵ In light of this, the Joint IOUs propose that RECs from the BioRAM PPAs should be *allocated* to Community Choice Aggregators and Electric

² ORA Comments at 1 (emphasis added).

³ ORA Comments at 1.

⁴ ORA Comments at 2.

⁵ See, e.g., Joint IOUs Comments at 3-4 (“Joint IOUs believe the most equitable approach...is an allocation approach that directly allocates the resource attributes to all benefitting customers, not an above-market approach that requires bundled service customers to retain all of the resource attributes and attempts to quantify those attributes’ “market value” using an administratively-set benchmark.”). See also Joint IOUs Comments at 9 (“Joint IOUs generally do not support use of a market benchmark for determining REC value. A better way to approach REC valuation is to allocate the RECs themselves to all benefitting customers.”).

Service Providers (“ESPs”) (collectively, “Alternative Suppliers”).⁶ The Joint IOUs’ proposal implicates a host of thorny policy and legal issues, and should be expressly rejected in this proceeding.

Thankfully even the Joint IOUs acknowledge that their REC allocation proposal should not be taken seriously in this proceeding.⁷ The Joint IOUs’ REC allocation proposal is being actively examined and litigated in the PCIA proceeding. Many parties, including CalCCA, oppose the Joint IOUs’ proposal, and even more parties question the legality and policy rationale for the proposal. Included among the skeptics is The Utility Reform Network (“TURN”), which observes “the IOUs’ proposal appears that it would strip RECs from underlying RPS-eligible resources and allocate unbundled RECs to Retail Sellers that are intended to qualify as Product Content Category (PCC) 1 resources for purposes of RPS compliance. Such a step might not be permissible under state law and current Commission policy, as the IOUs acknowledge, since the transfer of an unbundled REC cannot qualify for PCC 1 compliance.”⁸ For these reasons, the Commission should not entertain the Joint IOUs’ REC allocation proposal in this proceeding.

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⁶ See Joint IOU Comments at 9; note 16 (“The Joint IOUs have proposed in R.17-06-026, among other things, a REC allocation methodology [and] [i]f the Commission adopts the Joint Utilities’ allocation methodology in the [Power Charge Indifference Adjustment (“PCIA”) proceeding], the Joint Utilities believe it would be appropriate to utilize that methodology here.”).

⁷ See Joint IOUs Comments at 4; internal citations omitted (“[T]he Joint IOUs acknowledge that, to date, the Commission has not developed a general allocation approach for RECs that could be applied to these RPS-eligible biomass resources, and thus a valuation for the resource attributes that cannot be allocated (*i.e.*, RECs) may be appropriate and reasonable for the [BioRAM] PPAs.”) See also Joint IOUs Comments at 9; internal citations omitted (“Because there are a limited number of RECs expected from these [BioRAM] PPAs, an approach that is more administratively simple is appropriate and reasonable...at this time.”)

⁸ TURN Rebuttal Testimony in R.07-06-026, dated April 23, 2018, at 29.

C. The Joint IOUs' Criticism Of Administrative Benchmarks Is Self-Serving And Unwarranted For This Proceeding.

In their comments, the IOUs emphatically state that “[t]he Joint IOUs do not support the use of administratively set benchmarks for allocating costs.”⁹ The Joint IOUs assert that they “have little to no need for incremental renewable procurement at this time [and it] is unreasonable to require bundled service customers to purchase the departing load customers’ pro rata share of the [BioRAM] PPAs at the benchmark price when they have no need for it.”¹⁰ In light of this criticism, the Joint IOUs propose that RECs and Resource Adequacy (“RA”) attributes associated with the BioRAM PPAs be allocated to Alternative Suppliers, notwithstanding the Alternative Suppliers’ lack of need for the attributes.

For reasons discussed above, the Joint IOUs’ REC allocation proposal should be summarily rejected. The Joint IOUs’ allocation proposal with respect to RA attributes suffers from many of the same defects. Beyond substantive defects, the IOUs’ proposal is also procedurally flawed. This proceeding is simply not the proper venue to properly consider the IOUs’ allocation proposal. The BioRAM PPAs are extremely limited in scope (only approximately 150 megawatts, in total, for all of the IOUs). As such, it is somewhat incredulous for the Joint IOUs to suggest that they cannot accommodate or make use of the output from these resources. Likewise, the BioRAM PPAs’ respective terms are limited in duration (only five years), further mitigating and limiting any realistic impact upon the Joint IOUs from the BioRAM PPAs. As a matter of economy and fairness, it is simply not appropriate to use this proceeding to impose RECs and RA attributes on Alternative Suppliers. Consideration of the Joint IOUs’ allocation proposal is rightly before the Commission in the PCIA proceeding, and such consideration should not be prejudiced by a premature decision in this proceeding.

⁹ Joint IOUs Comments at 3.

¹⁰ Joint IOUs Comments at 3.

D. The Joint IOUs' Proposal To Value RECs Has Been Rightly Excluded From The Staff Proposal; A Benchmark Other Than The One In The Staff Proposal Should Only Flow From The PCIA Proceeding.

Chief among principles upon which the Staff Proposal is founded is the fact that the Staff Proposal “does not create any new RPS or Resource Adequacy (RA) processes or values.”¹¹ Contrary to this chief principle, the Joint IOUs continue to advocate for a *new* RPS process and valuation. Specifically, “the Joint IOUs recommend valuing RECs for purposes of the [Tree Mortality] NBC using Platts MW Daily mid-price for Portfolio Content Category (PCC) 1 resources.”¹² The Joint IOUs’ proposal has no basis in any Commission decision or proceeding, much less the PCIA proceeding. As such, the Joint IOUs’ proposal was rightly excluded from the Staff Proposal. The Joint IOUs’ proposal also suffers from other defects.

One of the primary flaws with the Platts index is that it is a short-term-based index. While the index may have some worth with respect to valuing short-term *reshuffling* of renewable resource portfolios, it should not be used in determining the REC value for the Tree Mortality NBC. The IOUs’ renewable portfolios, including the BioRAM PPAs, reflect mid- and long-term resources. Thus, an index based on short-term transactions, like Platts, is incongruent with the products being valued (namely, the BioRAM PPAs). Additionally, the short-term renewable resource market, on which the Joint IOUs’ Platts index is based, is too unstable to be relied upon to develop meaningful and reliable valuation amounts.

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¹¹ Staff Proposal at 1.

¹² Joint IOUs Comments at 9-10.

E. The Joint IOUs' Proposal To Allocate RA Attributes Has Been Rightly Excluded From The Staff Proposal; A Benchmark Other Than The One In The Staff Proposal Should Only Flow From The PCIA Proceeding.

As noted above, the Staff Proposal “does not create any new RPS or Resource Adequacy (RA) processes or values.”¹³ This is appropriate given the limited scope and duration of the BioRAM PPAs. The Joint IOUs depart from this approach and seek to create a new process with respect to BioRAM PPAs. Specifically, “[t]he Joint IOUs propose to allocate RA Credits to all LSEs through the existing [Cost Allocation Methodology (“CAM”)].¹⁴

In their comments, the Joint IOUs criticize CalCCA for not including in its Workshop presentation a critique of the Joint IOUs’ proposed use of the CAM for BioRAM PPAs.¹⁵ Accordingly, CalCCA provides the following abbreviated critique of the Joint IOUs’ proposal to allocate RA attributes under the CAM approach. CalCCA’s principal concern with the Joint IOUs’ proposal is one similar to the concern implied in the Staff Proposal: the Joint IOUs’ proposal *creates a new* RA process. The CAM approach has not been used outside of a reliability context. In particular, the CAM approach has not previously been used in connection with BioRAM PPAs. Yet, the Joint IOUs propose to implement the process here. As noted above, given the limited scope and duration of the BioRAM PPAs, it is inefficient, at best, to employ the CAM approach, which is a complicated and regulatory-intensive process. It is simpler and more congruent with the scope of the BioRAM PPAs to use a

¹³ See note 11, above (citing Staff Proposal at 1).

¹⁴ Joint IOUs Comments at 12. The CAM was adopted by the Commission in the context of reliability resources. (See [provide citation].)

¹⁵ See Joint IOUs Comments at 14 (“CalCCA’s presentation provides no explanation as to why the TM NBC RA should be “monetized” instead of simply allocated to each of the LSEs through the existing CAM process.”) Apparently the Joint IOUs’ criticism applies to the Staff Proposal, since RA associated with the BioRAM PPAs are also monetized under the Staff Proposal.

benchmark for purposes of RA valuation. This is accomplished under the Staff Proposal by using the Reference PPAs for an “apples-to-apples” benchmark that implicitly values RA above-market costs.¹⁶

Beyond being cumbersome and unjustified, use of the CAM approach in this context also unnecessarily and inappropriately creates a process that infringes on the statutory right of Community Choice Aggregators to maximize their own mix of generation resources. In the context of RA, the Legislature has determined that RA requirements should be established in a manner that achieves the following objective, among others: “Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.”¹⁷ One of the principal concerns over the CAM approach and other forced-allocation proposals is that they unnecessarily inhibit the ability of Community Choice Aggregators to determine their generation resources. The Joint IOUs have offered no justification as to why a forced-allocation approach in this context is justified, reasonable and consistent with statutory directives and principles. The statutory provision addressing the BioRAM PPAs speaks to recovery of costs from all customers on a nonbypassable basis, *not* the forced allocation of RA attributes.¹⁸ For these reasons, the Commission should continue to reject the Joint IOUs’ request to allocate RA attributes from the BioRAM PPAs to Alternative Suppliers.

F. The Joint IOUs’ Request To Exclude Green Tariff Shared Renewables Program Power Purchase Agreements Is Unpersuasive.

The Joint IOUs criticize the Staff Proposal’s reliance on Reference PPAs to determine a benchmark because, among other things, three of the five Reference PPAs were executed “pursuant to the [Green Tariff Shared Renewables (“GTSR”)] program” and, according to the Joint IOUs, “[t]he

¹⁶ See Staff Proposal at 3 (“[T]he average 2016 non- BioRAM Renewables PPA price is also an appropriate apples-to-apples benchmark to value the RA above market costs.”).

¹⁷ Public Utilities Code Section 380(a)(5). See also Public Utilities Code Section 454.51(d) (expressly providing a self-procurement option for Community Choice Aggregators with respect to renewable integration requirements).

GTSR program has resource limitations that restrict solicitation participation and affect total resource prices, such that GTSR procurement is not indicative of fully-competitive RPS markets.”¹⁹ To support their assertion, the Joint IOUs posit several reasons why the Staff Proposal’s benchmark would be “inflated to reflect the higher-costs of mandated GTSR resources.”²⁰

The Joint IOUs’ reasons for excluding GTSR resources from the benchmark are unpersuasive. The Joint IOUs have offered nothing in their list of reasons that materially distinguishes GTSR resources from other 2016 RPS-eligible resources. Solar resources predominant RPS-eligible resources, particularly in 2016, and 20 MW size limitation is entirely consistent with resources associated with the BioRAM PPAs, which average just over 25 MW in capacity. Beyond theoretical justification, which is unpersuasive, the Joint IOUs have failed to offer quantitative justification to materially distinguish GTSR resources. As such, the Commission should leave GTSR resources in the resource pool for the Reference PPAs.²¹

G. The Joint IOUs’ Assumption About True-ups Is Erroneous.

The Joint IOUs assert that a “true-up based on actual market outcomes” is necessary in order to avoid “bundled service customers alone bear[ing] the risk of any difference between that benchmark and actual revenues received....”²² Revealingly, the Joint IOUs level this concern at the Staff Proposal, but

¹⁸ See Staff Proposal at 1, note 1 (referencing Public Utilities Code Section 399.20.3(f)).

¹⁹ Joint IOUs Comments at 5.

²⁰ Joint IOUs Comments at 5. Included among these reasons are “GTSR projects must be new resources (i.e., not part of an existing facility), must be located within an IOU’s service territory, cannot be larger than 20 MW, and PPAs executed in 2016 were limited to solar resources.” (Joint IOUs Comments at 5.)

²¹ As mentioned by CalCCA in its opening comments, there is a concern “that there is a sufficiently deep pool of Reference PPAs (more specifically, energy delivered under the Reference PPAs) to allow for a credible determination of the benchmark.” (CalCCA Comments at 4.) Excluding GTSR resources from the pool of Reference PPAs, as proposed by the Joint IOUs, would only exacerbate this concern.

²² See Joint IOUs Comments at 3.

apparently do not have this same concern with respect to “the Joint IOUs’ proposed Platts REC index,”²³ which is likewise not subject to a true-up. The Joint IOUs’ concern is misplaced and erroneous. According to the Joint IOUs, the only way to avoid their postulated outcome is to fully unbundle and liquidate the BioRAM PPAs, with the inevitable result being that resource attributes associated with the BioRAM PPA will be undervalued. An example of this scenario with respect to RA attributes is borne out in the Staff Proposal as follows: “Energy Division’s analysis, via data received through the Procurement Review Group, confirms that the revenue results of the BioRAM RA auctions are lower than RA values...reported in the CPUC’s most recent RA Report....”²⁴ Unbundling and separately liquidating attributes associated with the BioRAM PPAs will inevitably reduce the overall value, as reflected in the Staff Proposal, which contemplates a *single, integrated* product:

Staff proposes that net above market BioRAM costs should be determined in a manner that treats the BioRAM renewable procurement as *a single product*, of which RECs and RA are *inherently integrated*. Accordingly, staff proposes that the BioRAM NBC should not separately value the components of RECs or RA, given that they are *inextricably valued* in the power purchase agreement (PPA) contract price.²⁵

H. The Joint IOUs’ Claims About Double-Counting Should Be Further Examined And Proven By Various Examples.

The Joint IOUs assert that the “Energy Division’s proposed [Tree Mortality] NBC calculation does not accurately measure above-market costs of the [BioRAM] PPAs as it *double counts* [BioRAM] PPA Energy Revenues and Ancillary Service Revenues.”²⁶ The Joint IOUs further describe the double-counting problem as follows:

This calculation subtracts actual [BioRAM] PPA Energy Revenues and Ancillary Service Revenue from all fixed and variable [BioRAM] PPA costs. Then, it further reduces that

²³ See Joint IOUs Comments at 3.

²⁴ Staff Proposal at 3, note 5.

²⁵ Staff proposal at 1.

²⁶ Joint IOUs Comments at 6 (emphasis added).

value by the “market value” of the [BioRAM] PPA’s integrated renewable product, which is defined as the Average 2016 Renewables PPA cost.²⁷

To remedy this situation, the Joint IOUs provide the following guidance: “If the Commission chooses to adopt the Energy Division staff proposal, which the Joint IOUs do not recommend, it should, at a minimum, eliminate the energy and ancillary services revenues term from the above-market calculation to avoid double-counting.”²⁸

The Joint IOUs appear to be correct. However, this can best be determined with reference to certain example calculations. Consistent with the request made by ORA above, CalCCA requests that any proposed decision adopting the Staff Proposal, as modified, provide sufficient example calculations so that parties can be assured that above-market costs of the BioRAM PPA are being fairly, accurately, and verifiably calculated.

II. CONCLUSION

CalCCA thanks the Commission for their consideration of these reply comments.

Dated: May 18, 2018

Respectfully submitted,

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²⁷ Joint IOUs Comments at 7.

²⁸ Joint IOUs Comments at 7.

**BEFORE THE PUBLIC UTILITIES COMMISSION
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Application of Southern California Edison
Company (U338E) for Approval of Energy
Efficiency Rolling Portfolio Business Plan.

Application 17-01-013
(Filed January 17, 2017)

And Related Matters

Application 17-01-014
Application 17-01-015
Application 17-01-016
Application 17-01-017

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

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And Related Matters

Application 17-01-014
Application 17-01-015
Application 17-01-016
Application 17-01-017

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure and Public Utilities Code Section 1701.1 and 1701.3(h)(2), Marin Clean Energy (“MCE”) hereby gives notice of the following *ex parte* meeting. The meeting included oral communications. The meeting took place on May 17, 2018 at 2:00 pm, took place on the phone, and lasted approximately 10 minutes. The attendees to the meeting included: Shannon O’Rourke, Advisor to Commissioner Peterman; Alice Stover, Director of Customer Programs for MCE; and Michael Callahan, Policy Counsel for MCE.

MCE communicated general support for the revised proposed decision. MCE supported the broader portfolio of programs to better meet cost-effectiveness standards; the addition of disadvantaged communities to meet the geographic component in the definition of hard-to-reach customers; and the reciprocal responsibilities in the joint cooperation memo.

MCE recommended the dicta related to the joint cooperation memo be aligned with the revised ordering paragraphs. MCE identified that the timing of the avoided cost updates would likely make it infeasible for administrators to include the correct total resource cost ("TRC") and

program administrator cost ("PAC") ratios in the joint cooperation memo, and requested they be excluded. MCE also noted that such information does not relate to the purpose of the memos, which is to describe how PAs will coordinate and collaborate during the business plan period.

Respectfully submitted,

/s/ Troy Nordquist

Troy Nordquist
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: tnordquist@mceCleanEnergy.org

May 18, 2018

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

Order Instituting Rulemaking to Develop
and Electricity Integrated Resource
Planning Framework and to Coordinate and
Refine Long-Term Procurement Planning
Requirements

Rulemaking 16-02-007
(Filed February 11, 2016)

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

Troy Nordquist
Legal Assistant
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: tnordquist@mceCleanEnergy.org

May 22, 2018

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

Order Instituting Rulemaking to Develop
and Electricity Integrated Resource
Planning Framework and to Coordinate and
Refine Long-Term Procurement Planning
Requirements

Rulemaking 16-02-007
(Filed February 11, 2016)

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rule 8.2 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following *ex parte* written communications.

The communication was initiated by MCE and occurred in writing via five separate emails on May 22, 2018 between 2:00 and 3:00 p.m. The emails included a written press release and a handout as attachments and was sent to: President Michael Picker; Commissioner Carla Peterman; Commissioner Clifford Rechtschaffen; Commissioner Liane Randolph; Commissioner Martha Guzman Aceves; Advisors to President Picker, James Ralph, Nidhi Thakar, David Peck, and Forest Kaser; Advisors to Commissioner Peterman, Jennifer Kalafut, John Reynolds, Ehren Seybert, and Shannon O’Rourke; Advisors to Commissioner Rechtschaffen, Sean Simon, Sandy Goldberg, Yuliya Shmidt, and Simi Rose George; Advisors to Commissioner Randolph, Rachel Peterson, Joanna Gubman, and Jason Houck; and Advisors to Commissioner Guzman Aceves, Michael Minkus, Candace Morey, and David Gamson. Though the communication was sent in five separate emails, the bodies of the emails all contained the same message.

A copy of the emails and attachments are included here as Appendix A.

Respectfully submitted,

/s/ Troy Nordquist

Troy Nordquist
Legal Assistant
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: tnordquist@mceCleanEnergy.org

May 22, 2018

APPENDIX A



Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Michael Callahan <mcallahan@mcecleanenergy.org>

Tue, May 22, 2018 at 2:16 PM

To: carla.peterman@cpuc.ca.gov, Jennifer Kalafut <jmk@cpuc.ca.gov>, john.reynolds@cpuc.ca.gov, ehren.seybert@cpuc.ca.gov, "O'Rourke, Shannon" <Shannon.O'Rourke@cpuc.ca.gov>

Cc: Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Dear Commissioner Peterman, Jennifer Kalafut, John Reynolds, Ehren Seybert and Shannon O'Rourke:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

- the potential to receive lower energy prices and improved credit terms for future contracts,
- access to new sources of energy supply,
- validation of the CCA business model from an internationally-recognized rating agency, and
- assurance for customers that MCE's financial strength is sound and that it will continue to be a reliable source of energy and services over the long term.
- Moody's recognized that a key aspect of the value offered by MCE and other California CCAs is the requirement that renewable and carbon-free energy be a major component of customers' power supply mix. This value is one of the most significant contributing factors to the strength of the long-term business model. Renewable energy accounted for 62% of MCE's retail sales in 2017 and 89% of all MCE's energy came from greenhouse gas-free sources. Most of these resources are under long-term contracts of 15, 20 and 25 years as shown in the attached.

The attached press release contains additional information, but feel free to reach out if you have any questions.

MCE will serve an Ex-Parte Notice today on the service lists for the CCA Rulemaking (R.03-10-003) and the Integrated Resource Planning Rulemaking (R.16-02-007).

Best regards,

Michael Callahan

Policy Counsel, MCE

415.464.6045 | mcallahan@mceCleanEnergy.org

mceCleanEnergy.org

Join our Facebook group and sign up for our e-newsletter!

2 attachments

New CA Renewable Projects_08312017.pdf
722K

Moody's Credit Rating Press Release.pdf
425K



Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Michael Callahan <mcallahan@mcecleanenergy.org>

Tue, May 22, 2018 at 2:16 PM

To: michael.picker@cpuc.ca.gov, "Ralph, James" <James.Ralph@cpuc.ca.gov>, nidhi.thakar@cpuc.ca.gov, "Peck, David B."

<david.peck@cpuc.ca.gov>, forest.kaser@cpuc.ca.gov

Cc: Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Dear President Picker, James Ralph, Nidhi Thaker, David Peck, and Forest Kaser:

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Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:42 PM

To: clifford.rechtschaffen@cpuc.ca.gov, "Simon, Sean A." <sean.simon@cpuc.ca.gov>, "Goldberg, Sandy" <sandy.goldberg@cpuc.ca.gov>, "Shmidt, Yuliya" <yuliya.shmidt@cpuc.ca.gov>, Simi.George@cpuc.ca.gov

Cc: Shalini Swaroop <:sswaroop@mcecleanenergy.org>

Dear Commissioner Rechtschaffen, Sean Simon, Yuliya Shmidt, Simi Rose George & Sandy Goldberg:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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Best regards,

Nathaniel Malcolm

Nathaniel Malcolm

Policy Counsel, MCE

1125 Tamalpais Ave.

San Rafael, CA 94901

415.464.6048 | nmalcolm@mcecleanenergy.org

mceCleanEnergy.org

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Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:40 PM

To: Martha.GuzmanAceves@cpuc.ca.gov, "Minkus, Michael J." <Michael.Minkus@cpuc.ca.gov>, candace.morey@cpuc.ca.gov, david.gamson@cpuc.ca.gov

Cc: Shalini Swaroop <:sswaroop@mcecleanenergy.org>

Dear Commissioner Guzman-Aceves, Michael Minkus, Candace Morey & David Gamson:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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Nathaniel Malcolm

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Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:26 PM

To: liane.randolph@cpuc.ca.gov, rachel.peterson@cpuc.ca.gov, Joanna.Gubman@cpuc.ca.gov, jason.houck@cpuc.ca.gov

Cc: CC Song <csong@mcecleanenergy.org>

Dear Commissioner Randolph, Rachel Peterson, Joanna Gubman & Jason Houck:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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FOR IMMEDIATE RELEASE

May 22, 2018

Press Contact:

David McNeill | Finance Manager
(415) 464-6025 | dmcneil@mceCleanEnergy.org

Moody's Assigns Baa2 Issuer Rating to MCE *Investment-Grade Rating Indicates Stable Outlook*

San Rafael and Concord, Calif. — On May 16, Moody's Investors Service assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term, and MCE's outlook is stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating.

"MCE is pleased to have reached this important milestone in our history. An investment-grade credit rating reflects our firm commitment to ensuring MCE's financial strength and enabling the agency to continue delivering on its mission. It will enable MCE to purchase renewable energy at even better prices and pass those benefits on to its customers," said Dawn Weisz, CEO of MCE. "A Baa2 Issuer Rating from Moody's further validates the CCA model in California and its ability to offer affordable, renewable and reliable service to customers."

The Baa2 Issuer Rating reflects the strength of the California Joint Power Agency (JPA) statute and the MCE JPA agreement, which together underpin MCE's creation and business model, and fortifies the ongoing stability of its existing customer base.

The rating further recognizes the local Board-regulated rate-setting authority afforded to MCE, its established track record of operations, consistently improving financial performance, and the economic strengths within its growing service area. At year-end FY 2017, MCE had unrestricted cash of \$37 million, supplemented by a \$25 million committed line of credit that has no conditionality for advances. MCE projects cash on hand to exceed \$60 million by FY 2019. MCE's working capital needs are modest, and MCE is typically able to generate positive cash flow each month.

Several prominent institutional investors in California renewable projects require that energy buyers, such as MCE, have an investment grade credit rating. The benefits of a Baa2 credit rating include:

- the potential to receive lower energy prices and improved credit terms for future contracts;
- access to new sources of energy supply;
- validation of the CCA business model from an internationally-recognized rating agency; and
- assurance for customers that MCE's financial strength is sound and that it will continue to be a reliable source of energy and services over the long term.

Moody's recognized that a key aspect of the value offered by MCE and other California CCAs is the requirement that renewable and carbon-free energy be a major component of customers' power supply mix. This value is one of the most significant contributing factors to the strength of the long-term business model. During 2017, MCE projects that renewable energy accounted for 62% of its retail sales, and that 89% of energy came from greenhouse gas-free sources.

[Read Moody's full press release here.](#)

###

About MCE: MCE is a not-for-profit, public electricity provider that gives customers the choice of having 50% to 100% of their electricity supplied from clean, renewable sources such as solar, wind, bioenergy, geothermal, and hydroelectric at competitive rates. MCE provides service to approximately 450,000 California customers in Marin County, Napa County, unincorporated Contra Costa County, and the cities of Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek. For more information about MCE, visit mceCleanEnergy.org.

TOGETHER WE'RE BUILDING A CLEANER ENERGY FUTURE FOR CALIFORNIA | 2017

From 2010–2015, MCE customers have **eliminated more than 185,751 metric tons of greenhouse gas emissions** — the equivalent of removing 39,237 cars from the road for one year or sequestering the same amount of carbon as 175,833 acres of forest in one year.

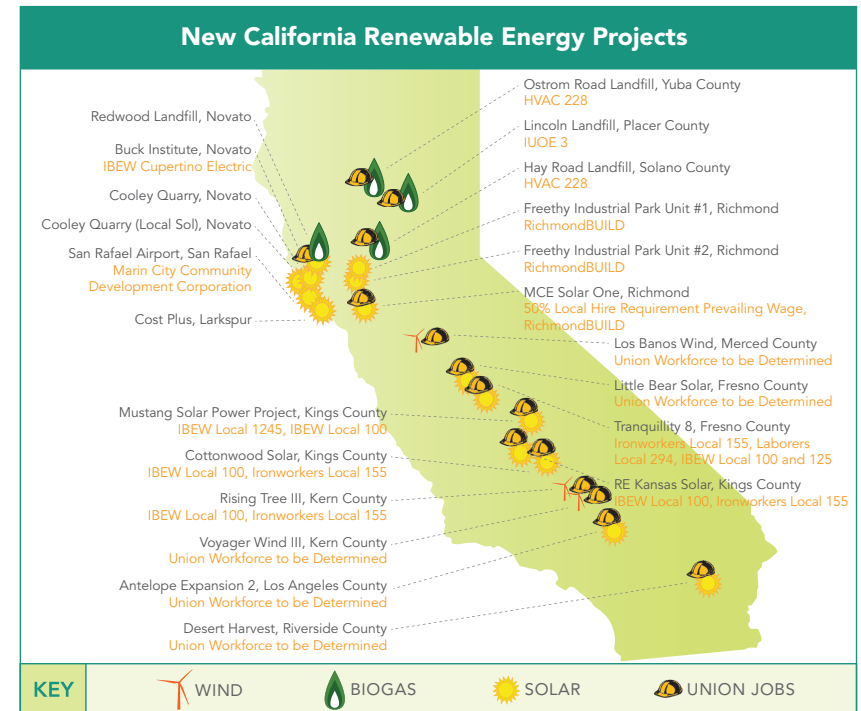
BUILDING NEW RENEWABLES

MCE and its partners have committed over **\$1.6 billion to build 813 MW of new renewable energy projects in California**. This includes \$903 million for solar, \$665 million for wind, and \$17 million for biogas projects. MCE was likely California's largest purchaser of renewable energy in 2016. Below is a list of MCE's new California renewable energy projects currently under contract.

	RESOURCE & CONTRACT TYPE ¹	RESOURCE PROVIDER / PROJECT NAME	LOCATION	PROJECT CAPACITY (MW)	MCE SERVICE START DATE	CONTRACT LENGTH (YEARS)
LOCAL (MCE Service Area)	Solar FIT	San Rafael Airport	San Rafael, Marin Co.	1	2012	20
	Solar PPA	Dominion / Buck Institute of Research on Aging	Novato, Marin Co.	1	2016	25
	Solar FIT	Rawson, Blum & Leon / Cost Plus Plaza	Larkspur, Marin Co.	0.265	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #1	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #2	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	REP Energy / Cooley Quarry	Novato, Marin Co.	0.5	2017	20
	Solar FIT	REP Energy / Cooley Quarry	Novato, Marin Co.	1 Local Sol ²	2017	20
	Biogas PPA	Waste Management / Redwood Landfill	Novato, Marin Co.	3.6	2017	20
	Solar PPA	MCE / Solar One	Richmond, Contra Costa Co.	10.5	2017	25
	NEARBY (<100 Miles)	Biogas PPA	G2 Energy / Hay Road Landfill	Vacaville, Solano Co.	1.6	2013
Biogas PPA		Genpower / Lincoln Landfill	Lincoln, Placer Co.	4.8	2013	20
Biogas PPA		G2 Energy / Ostrom Road Landfill	Wheatland, Yuba Co.	1.9	2013	18
IN STATE (Within California)	Solar PPA	Dominion / RE Kansas Solar	Stratford, Kings Co.	20	2015	3
	Solar PPA	Dominion / Cottonwood Solar	Stratford, Kings Co.	23	2015	25
	Wind PPA	EDP Renewables / Rising Tree III	Mojave, Kern Co.	99	2015	3.5
	Solar PPA	Recurrent Energy / Mustang Solar Power Project	Lemoore, Kings Co.	30	2018	15
	Solar PPA	Recurrent Energy / Tranquillity 8	Tranquillity, Fresno Co.	100	2018	25
	Solar PPA	sPower / Antelope Expansion 2	Lancaster, Los Angeles Co.	105	2018	20
	Wind PPA	Terra-Gen / Voyager Wind III	Mojave, Kern Co.	42	2018	12
	Wind PPA	Terra-Gen / Los Banos Wind	Los Banos, Merced Co.	125	2018	12
	Solar PPA	First Solar / Little Bear Solar	Mendota, Fresno Co.	40 up to 160 ³	2020	20
Solar PPA	EDF Renewables / Desert Harvest	Desert Center, Riverside Co.	80	2020	20	

2,800+ CALIFORNIA JOBS

MCE's renewable projects have supported more than 2,800 California jobs⁴ resulting in 1.2 million union labor hours. MCE's sustainable workforce policy outlines support for local businesses, union members, training and apprenticeship programs, and support for green and sustainable businesses.



1. FIT=Feed-In Tariff; PPA=Power Purchase Agreement
2. 100% solar energy service option produced by a local solar farm within MCE's service area.
3. Project size will increase to 160 MW with inclusion of new MCE communities.
4. MCE uses the National Renewable Energy Laboratory's Jobs and Economic Development Impacts Model to provide consistent and reasonably accurate estimates of direct and indirect jobs involved in MCE's power contracting efforts and general operations.

FOR MORE INFORMATION:
mceCleanEnergy.org/energy-sources
info@mceCleanEnergy.org



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

Order Instituting Rulemaking to Implement
Portions of AB117 concerning Community
Choice Aggregation

Rulemaking 03-10-003
(Filed October 2, 2003)

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

Troy Nordquist
Legal Assistant
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: tnordquist@mceCleanEnergy.org

May 22, 2018

**BEFORE THE PUBLIC UTILITIES COMMISSION
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(Filed October 2, 2003)

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five separate emails, the bodies of the emails all contained the same message. A copy of the emails and attachments are included here as Appendix A.

Respectfully submitted,

/s/ Troy Nordquist

Troy Nordquist
Legal Assistant
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: tnordquist@mceCleanEnergy.org

May 22, 2018

APPENDIX A



Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

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Tue, May 22, 2018 at 2:16 PM

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Best regards,

Michael Callahan

Policy Counsel, MCE

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- Moody's recognized that a key aspect of the value offered by MCE and other California CCAs is the requirement that renewable and carbon-free energy be a major component of customers' power supply mix. This value is one of the most significant contributing factors to the strength of the long-term business model. Renewable energy accounted for 62% of MCE's retail sales in 2017 and 89% of all MCE's energy came from greenhouse gas-free sources. Most of these resources are under long-term contracts of 15, 20 and 25 years as shown in the attached.

The attached press release contains additional information, but feel free to reach out if you have any questions.

MCE will serve an Ex-Parte Notice today on the service lists for the CCA Rulemaking (R.03-10-003) and the Integrated Resource Planning Rulemaking (R.16-02-007).

Best regards,

Michael Callahan

Policy Counsel, MCE

415.464.6045 | mcallahan@mceCleanEnergy.orgmceCleanEnergy.org

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2 attachments

 **New CA Renewable Projects_08312017.pdf**
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425K



Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:42 PM

To: clifford.rechtschaffen@cpuc.ca.gov, "Simon, Sean A." <sean.simon@cpuc.ca.gov>, "Goldberg, Sandy" <sandy.goldberg@cpuc.ca.gov>, "Shmidt, Yuliya" <yuliya.shmidt@cpuc.ca.gov>, Simi.George@cpuc.ca.gov

Cc: Shalini Swaroop <:sswaroop@mcecleanenergy.org>

Dear Commissioner Rechtschaffen, Sean Simon, Yuliya Shmidt, Simi Rose George & Sandy Goldberg:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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Best regards,

Nathaniel Malcolm

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Policy Counsel, MCE

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Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:40 PM

To: Martha.GuzmanAceves@cpuc.ca.gov, "Minkus, Michael J." <Michael.Minkus@cpuc.ca.gov>, candace.morey@cpuc.ca.gov, david.gamson@cpuc.ca.gov

Cc: Shalini Swaroop <:sswaroop@mcecleanenergy.org>

Dear Commissioner Guzman-Aceves, Michael Minkus, Candace Morey & David Gamson:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

MCE Receives Investment-Grade Credit Rating

Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Tue, May 22, 2018 at 2:26 PM

To: liane.randolph@cpuc.ca.gov, rachel.peterson@cpuc.ca.gov, Joanna.Gubman@cpuc.ca.gov, jason.houck@cpuc.ca.gov

Cc: CC Song <csong@mcecleanenergy.org>

Dear Commissioner Randolph, Rachel Peterson, Joanna Gubman & Jason Houck:

I wanted to share the exciting news that Moody's Investors Service has assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term and found MCE's outlook to be stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating, and the benefits of a Baa2 credit rating include:

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FOR IMMEDIATE RELEASE

May 22, 2018

Press Contact:

David McNeill | Finance Manager
(415) 464-6025 | dmcneil@mceCleanEnergy.org

Moody's Assigns Baa2 Issuer Rating to MCE *Investment-Grade Rating Indicates Stable Outlook*

San Rafael and Concord, Calif. — On May 16, Moody's Investors Service assigned a first-time Baa2 Issuer Rating to MCE. Moody's Issuer Rating is an independent assessment of MCE's financial strength over the long term, and MCE's outlook is stable. MCE is the first Community Choice Aggregation (CCA) program to obtain an investment-grade credit rating.

"MCE is pleased to have reached this important milestone in our history. An investment-grade credit rating reflects our firm commitment to ensuring MCE's financial strength and enabling the agency to continue delivering on its mission. It will enable MCE to purchase renewable energy at even better prices and pass those benefits on to its customers," said Dawn Weisz, CEO of MCE. "A Baa2 Issuer Rating from Moody's further validates the CCA model in California and its ability to offer affordable, renewable and reliable service to customers."

The Baa2 Issuer Rating reflects the strength of the California Joint Power Agency (JPA) statute and the MCE JPA agreement, which together underpin MCE's creation and business model, and fortifies the ongoing stability of its existing customer base.

The rating further recognizes the local Board-regulated rate-setting authority afforded to MCE, its established track record of operations, consistently improving financial performance, and the economic strengths within its growing service area. At year-end FY 2017, MCE had unrestricted cash of \$37 million, supplemented by a \$25 million committed line of credit that has no conditionality for advances. MCE projects cash on hand to exceed \$60 million by FY 2019. MCE's working capital needs are modest, and MCE is typically able to generate positive cash flow each month.

Several prominent institutional investors in California renewable projects require that energy buyers, such as MCE, have an investment grade credit rating. The benefits of a Baa2 credit rating include:

- the potential to receive lower energy prices and improved credit terms for future contracts;
- access to new sources of energy supply;
- validation of the CCA business model from an internationally-recognized rating agency; and
- assurance for customers that MCE's financial strength is sound and that it will continue to be a reliable source of energy and services over the long term.

Moody's recognized that a key aspect of the value offered by MCE and other California CCAs is the requirement that renewable and carbon-free energy be a major component of customers' power supply mix. This value is one of the most significant contributing factors to the strength of the long-term business model. During 2017, MCE projects that renewable energy accounted for 62% of its retail sales, and that 89% of energy came from greenhouse gas-free sources.

[Read Moody's full press release here.](#)

###

About MCE: MCE is a not-for-profit, public electricity provider that gives customers the choice of having 50% to 100% of their electricity supplied from clean, renewable sources such as solar, wind, bioenergy, geothermal, and hydroelectric at competitive rates. MCE provides service to approximately 450,000 California customers in Marin County, Napa County, unincorporated Contra Costa County, and the cities of Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek. For more information about MCE, visit mceCleanEnergy.org.

TOGETHER WE'RE BUILDING A CLEANER ENERGY FUTURE FOR CALIFORNIA | 2017

From 2010–2015, MCE customers have **eliminated more than 185,751 metric tons of greenhouse gas emissions** — the equivalent of removing 39,237 cars from the road for one year or sequestering the same amount of carbon as 175,833 acres of forest in one year.

BUILDING NEW RENEWABLES

MCE and its partners have committed over **\$1.6 billion to build 813 MW of new renewable energy projects in California**. This includes \$903 million for solar, \$665 million for wind, and \$17 million for biogas projects. MCE was likely California's largest purchaser of renewable energy in 2016. Below is a list of MCE's new California renewable energy projects currently under contract.

	RESOURCE & CONTRACT TYPE ¹	RESOURCE PROVIDER / PROJECT NAME	LOCATION	PROJECT CAPACITY (MW)	MCE SERVICE START DATE	CONTRACT LENGTH (YEARS)
LOCAL (MCE Service Area)	Solar FIT	San Rafael Airport	San Rafael, Marin Co.	1	2012	20
	Solar PPA	Dominion / Buck Institute of Research on Aging	Novato, Marin Co.	1	2016	25
	Solar FIT	Rawson, Blum & Leon / Cost Plus Plaza	Larkspur, Marin Co.	0.265	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #1	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #2	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	REP Energy / Cooley Quarry	Novato, Marin Co.	0.5	2017	20
	Solar FIT	REP Energy / Cooley Quarry	Novato, Marin Co.	1 Local Sol ²	2017	20
	Biogas PPA	Waste Management / Redwood Landfill	Novato, Marin Co.	3.6	2017	20
	Solar PPA	MCE / Solar One	Richmond, Contra Costa Co.	10.5	2017	25
	NEARBY (<100 Miles)	Biogas PPA	G2 Energy / Hay Road Landfill	Vacaville, Solano Co.	1.6	2013
Biogas PPA		Genpower / Lincoln Landfill	Lincoln, Placer Co.	4.8	2013	20
Biogas PPA		G2 Energy / Ostrom Road Landfill	Wheatland, Yuba Co.	1.9	2013	18
IN STATE (Within California)	Solar PPA	Dominion / RE Kansas Solar	Stratford, Kings Co.	20	2015	3
	Solar PPA	Dominion / Cottonwood Solar	Stratford, Kings Co.	23	2015	25
	Wind PPA	EDP Renewables / Rising Tree III	Mojave, Kern Co.	99	2015	3.5
	Solar PPA	Recurrent Energy / Mustang Solar Power Project	Lemoore, Kings Co.	30	2018	15
	Solar PPA	Recurrent Energy / Tranquillity 8	Tranquillity, Fresno Co.	100	2018	25
	Solar PPA	sPower / Antelope Expansion 2	Lancaster, Los Angeles Co.	105	2018	20
	Wind PPA	Terra-Gen / Voyager Wind III	Mojave, Kern Co.	42	2018	12
	Wind PPA	Terra-Gen / Los Banos Wind	Los Banos, Merced Co.	125	2018	12
	Solar PPA	First Solar / Little Bear Solar	Mendota, Fresno Co.	40 up to 160 ³	2020	20
Solar PPA	EDF Renewables / Desert Harvest	Desert Center, Riverside Co.	80	2020	20	

2,800+ CALIFORNIA JOBS

MCE's renewable projects have supported more than 2,800 California jobs⁴ resulting in 1.2 million union labor hours. MCE's sustainable workforce policy outlines support for local businesses, union members, training and apprenticeship programs, and support for green and sustainable businesses.



1. FIT=Feed-In Tariff; PPA=Power Purchase Agreement
2. 100% solar energy service option produced by a local solar farm within MCE's service area.
3. Project size will increase to 160 MW with inclusion of new MCE communities.
4. MCE uses the National Renewable Energy Laboratory's Jobs and Economic Development Impacts Model to provide consistent and reasonably accurate estimates of direct and indirect jobs involved in MCE's power contracting efforts and general operations.

FOR MORE INFORMATION:
mceCleanEnergy.org/energy-sources
info@mceCleanEnergy.org



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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

**OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

PUBLIC VERSION**



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June 1, 2018

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List of Acronyms

CalCCA Brief

A.	Application
A&G	Administrative and General
AB	Assembly Bill
ABS	Asset Backed Securities
ACC	Avoided Cost Calculator
ALJ	Administrative Law Judge
AReM/DACC	Alliance for Retail Energy Markets, Direct Access Customer Coalition
AS	Ancillary Services
CAISO	California Independent System Operator
CalCCA	California Community Choice Association
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregation
CDWR	California Department of Water Resources
CG	Customer Generator/tion
CLECA	California Large Energy Consumers Association
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CT	Combustion Turbine
CTC	Competition Transition Charge
D.	Decision
DA	Direct Access
DG	Distributed Generation
DER	Distributed Energy Resources
DOE	US Department of Energy
DR	Demand Response
EE	Energy Efficiency
EECC	Equitable Energy Choice for Californians
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
GAM	Green Allocation Mechanism
GHG	Greenhouse Gas
GRC	General Rate Case
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
LSE	Load Serving Entity
MEA	Marin Energy Authority (fka MCE – Marin Clean Energy)
MEC	Marginal Energy Cost
MGCC	Marginal Generation Capacity Cost

MNDA	Modified Non-disclosure Agreement
MPB	Market Price Benchmark
MPR	Market Price Referent
NBC	Non Bypassable Charge
NPC	Nevada Power Company
NPV	Net Present Value
NQC	Net Qualifying Capacity
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PCC	Product Content Category
PCIA	Power Charge Indifference Adjustment
PCL	Product Content Label
PG&E	Pacific Gas and Electric Company
PMM	Portfolio Monetization Mechanism
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PUCN	Public Utility Commission of Nevada
PWRPA	Power and Water Resource Pooling Authority
R.	Rulemaking
RA	Resource Adequacy
REC	Renewable Energy Credit
RFO	Request for Offer
ROC	Ratepayer Obligation Charge
RPS	Renewables Portfolio Standard
RRB	Rate Reduction Bonds
TURN	The Utility Reform Network
SB	Senate Bill
SEC	US Securities and Exchange Commission
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SONGS	San Onofre Nuclear Generating Station
SPA	Staggered Portfolio Auction
SPE	Special Purpose Legal Entity
TAC	Transmission Access Charge
UCAN	Utility Consumers' Action Network
UOG	Utility Owned Generation
URG	Utility Retained Generation
VAAC	Voluntary Allocation & Auction Clearinghouse
VEPP	Vermont Electric Power Producers
WACC	Weighted Average Cost of Capital

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

**OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

Pursuant to Rule 13.11 of the California Public Utilities Commission’s Rules of Practice and Procedure and the Amended Scoping Memo and Ruling of Assigned Commissioner issued March 2, 2018, in Rulemaking 17-06-026, the California Community Choice Association (CalCCA) submits this concurrent opening brief. Each section identifies the corresponding section of the common briefing outline generally agreed to by the parties.

I. INTRODUCTION AND EXECUTIVE SUMMARY (Common Outline §§I & II)

The Joint Utilities estimate that from 2018 through 2041, uneconomic portfolio costs will total an estimated ***\$49.68 billion***, with more than half of that amount forecast for Pacific Gas and Electric Company’s (PG&E’s) service territory.¹ This staggering estimate requires the Commission to entertain two opposing views: “either the investor-owned utility resource portfolios are wildly ‘out of the money’ or the benchmark used to evaluate market value requires reform.”² While the Joint Utilities’ portfolios present real and significant problems, the magnitude of these problems is considerably exaggerated by the use of a “market price” benchmark that undervalues those portfolios under the current Power Charge Indifference

¹ See IOU Projections of Above-Market Costs, Workpapers to Appendix D of Exhibit IOU-5.

² Exh. CalCCA-1, Prepared Direct Testimony of the California Community Choice Association, at 1-1:4-7.

Adjustment (PCIA) methodology (Current Methodology). Moreover, while the Joint Utilities contend that the Current Methodology shifts responsibility for uneconomic costs from departing load customers to bundled customers, CalCCA reaches the opposite conclusion: the Current Methodology, by undervaluing portfolio resources, shifts costs from bundled customers to departing load customers. While there is no certain way to determine the extent of the cost shift, CalCCA estimates that the Current Methodology results in a cost shift from bundled to departing load customers for 2018 of up to \$492 million annually by PG&E and up to \$25 million annually by SCE, increasing as departing load increases over time.³ The Current Methodology thus requires correction.

While the allocation of uneconomic costs is the Commission’s central mission in this rulemaking, the issue cannot be viewed in isolation, despite the Joint Utilities’ contentions to the contrary.⁴ The impact on customers of changes in the cost allocation will depend partly on the magnitude of the costs being allocated. To mitigate customer impacts requires consideration of measures to reduce total portfolio costs; securitization of utility owned generation (UOG) assets, buydown and securitization of existing long-term power purchase agreements (PPAs) and changes in portfolio management practices can reduce existing uneconomic costs and prevent their further accumulation. In addition, the manner in which existing portfolio resources are owned and controlled will not only affect total portfolio costs, but will influence the extent of “double procurement” by other LSEs. Critically, all of these issues – the magnitude of costs, the

³ The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE. If SCE’s CCA departing load were assumed to rise to 40.9% as it is in PG&E’s territory, then the indicative 2018 cost shift for SCE would increase from \$25 million to \$264 million. Exh. CalCCA-1 at 2A-14; Footnotes 14 and 15.

⁴ The Joint Utilities have made clear from the outset that their “interest in this proceeding is limited solely to ensuring appropriate cost allocation between groups of customers.” Exh. IOU-1, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Power Charge Indifference Adjustment, Prepared Testimony (Public Version), at 1-3:20-22.

allocation of costs and the allocation of resources – carry the potential to interfere with continuing CCA formation and operation.

It would be tempting for the Commission, given its traditional regulatory orientation, to focus the design of any solution on protecting bundled customers. Given the potential impacts on CCAs, the strength of Legislative directives supporting their formation, and SB 350’s clear mandate to prevent cost shifts in *any* direction, the Commission must also view the problems and solutions in this rulemaking through the lens of Community Choice Aggregation. The Legislature enacted this program to permit customers to “aggregate their electrical loads as members of their local community with community choice aggregators.”⁵ The program has been a fixture of the California electricity market since 1996, when it was originally enacted in Assembly Bill (AB) 1890.⁶ While the program was suspended by AB 1X⁷ in 2001 in the wake of the energy crisis, the Legislature was quickly reauthorized and modified the program through AB 117 in 2002,⁸ demonstrating the state’s commitment to the idea of local governments serving their own communities.

The Legislature envisioned CCAs as partners with the utilities and state agencies in driving energy efficiency and conservation,⁹ increasing reliance on renewable resources¹⁰ and ensuring grid reliability.¹¹ This well-conceived partnership carries the potential to accelerate and enhance achievement of important state goals – including climate change and social justice – and to facilitate the design of products and services that best meet consumers’ needs. CCAs play a

⁵ Assembly Bill 117 (Stats. 2002, ch. 838) (hereafter, AB 117).

⁶ Assembly Bill 1890 (Stats. 1996, ch. 854) (hereafter, AB 1890).

⁷ Assembly Bill 1 (Stats. 2001, 1st Ex. Session 2001, ch. 4) (hereafter, AB IX).

⁸ AB 117, *supra*.

⁹ *Id.*

¹⁰ Senate Bill 1078 (Stats. 2001, ch. 516) (hereafter, SB 1078).

¹¹ Cal. Pub. Util. Code §380.

unique role in this partnership due to their ability to better understand and respond to the needs of the communities they serve, leverage coordination with local governments and, in the longer term, leverage local government financing. CCAs have embarked on this path through the creation of programs aimed to develop small, local renewable resources,¹² encourage energy efficiency, drive transportation electrification, and assist low-income communities.¹³ Their efforts are leading the way for other newly launched and future CCAs to follow and enhance this early progress.

The Legislature has tasked the Commission with ensuring the success of its vision. In realizing that vision, the Commission must:

- Enforce cooperation by the utilities “with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs;”¹⁴
- “Foster fair competition” between CCAs and utilities;¹⁵
- Certify CCA implementation plans;¹⁶
- Prevent cost shifts between bundled and departing load customers;¹⁷
- Ensure that a CCA is “solely responsible” for its own procurement, unless otherwise permitted by statute;¹⁸ and
- Ensure CCA RPS¹⁹ and RA compliance.²⁰

More generally, the Commission must “provide Community Choice Aggregators with the opportunity to compete on a fair and equal basis with other load serving entities, and to prevent

¹² See, e.g., <https://www.maccleanenergy.org/local-projects/>
¹³ Ex. Cal CCA-3, Exh. 1-B; see also, e.g., <https://sonomacleanpower.org/faq/>.
¹⁴ *Id.* §366.2(c)(9)-(11)
¹⁵ Senate Bill 790 (Stats. 2011, ch. 599, §2(h)) (hereafter, SB 790).
¹⁶ Cal. Pub. Util. Code §366.2(c)(5)-(8).
¹⁷ *Id.* §366.2(a)(4); see also *id.* §366.3.
¹⁸ *Id.* §366.2(g).
¹⁹ *Id.* §399.11.
²⁰ *Id.* §380.

investor-owned electric utilities from using their position or market power to undermine the development or operation of aggregators.”²¹ The Commission also maintains its general obligation to adopt rates that are just and reasonable.²²

Today roughly 40% of PG&E’s and 4% of SCE’s native load is served by Energy Service Providers (ESPs) or Community Choice Aggregators (CCAs).²³ With more CCAs preparing to launch in 2018, the program has the potential to reach 85% of load in the utilities service territory by the mid-2020s.²⁴ As this transition continues to unfold, CalCCA’s proposals, summarized below, allow the Commission to fulfill each of its statutory responsibilities, as well as the Scoping Memo’s Guiding Principles. These proposals also address the three major areas of concern: the magnitude of uneconomic costs, the allocation of these costs and the ownership and control of portfolio resources. CalCCA proposes a measured and phased transition toward a model that addresses these issues in a durable way, ensuring adequate time for studied decisionmaking and enabling California to realize its CCA vision.

A. The Commission Plays a Central Statutory Role in Realizing the Legislature’s Vision for a Partnership Among the State, Joint Utilities and Other LSEs to Implement State Policy Goals.

1. The Commission Must Prevent Cost Shifts Between Bundled and Departing Load Customers

This rulemaking was instituted primarily to implement the Commission’s responsibility to prevent cost shifts between bundled and departing load customers.²⁵ The Scoping Memo declares preventing cost shifts as the “Overall Goal of this Proceeding.”²⁶ As the Scoping Memo

²¹ D.12-12-036 at 2; *see* SB 790 at § 2(h); *see also* Cal. Pub. Util. Code § 707(a)(4)(A).

²² Cal. Pub. Util. Code §451.

²³ Exh. IOU-1 at 1-1:18-23.

²⁴ *Id.*

²⁵ Scoping Memo at 20.

²⁶ Scoping Memo at 13.

observes, however, the Legislative directives to avoid cost shifts do not solely protect bundled customers. The statutory prohibitions of cost shifting require equal treatment, prevent cost shifts from departing load to bundled customers *and* from bundled to departing load customers.²⁷ The object of this rulemaking thus is to provide equal treatment for bundled and departing load customers, and it should not be viewed solely as an opportunity to reduce or maintain bundled rates.

With respect to CCA departing load, the Legislature has defined the scope of cost responsibility for “estimated net unavoidable electricity purchase contract costs.”²⁸ The Legislature further has mandated that the costs:

...shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.²⁹

Relying on the scope directed by the Legislature, CalCCA concludes that the Current Methodology does not achieve “indifference” between these customer groups. The Current Methodology results in a cost shift from bundled to departing load customers for 2018 of up to \$492 million annually by PG&E and up to \$25 million annually by SCE, increasing as departing load increases over time.³⁰

“Uneconomic,” “stranded” or “above-market” portfolio costs, in the context of the PCIA calculation for CCA departing load customers, are most easily understood as the difference between portfolio costs and portfolio value. Uneconomic costs have generally been defined as

²⁷ See Cal. Pub. Util. Code §366.3.

²⁸ Cal. Pub. Util. Code §366.2(f)(2).

²⁹ *Id.* §366.2(g).

³⁰ The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE. If SCE’s CCA departing load were assumed to rise to 40.9% as it is in PG&E’s territory, then the indicative 2018 cost shift for SCE would increase from \$25 million to \$264 million. Exh. CalCCA-1 at 2A-14: Footnotes 14 and 15.

costs “that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market.”³¹ The analysis, however, does not stop with an examination of “market” prices, as the Joint Utilities would suggest. The Legislature has made clear that any costs not recoverable in the market “shall be reduced by the value of any benefits that remain with bundled service customers....”³² In other words, uneconomic costs to be allocated through the PCIA are “above-market” costs offset by remaining portfolio value or, as defined by AB 117, the “estimated net unavoidable costs.”³³

While costs are relatively straightforward to identify, estimating value is challenging due to California’s regulatory framework, as the Joint Utilities admit.³⁴ Using a reasonable method of estimating value, however, the Current Methodology *understates the value* of the Joint Utilities’ portfolios. It fails to recognize valuable attributes in the portfolios, including GHG-free resource value, understating the annual 2018 value by as much as \$655 million for PG&E and \$219 million for SCE.³⁵ It also materially undervalues the Joint Utilities’ portfolios by as much as \$475 million for PG&E and \$298 million for SCE by relying on short-term RA prices as a proxy for capacity value,³⁶ and by as much as \$10 million for each of PG&E and SCE by failing to recognize the value of ancillary services.³⁷ In doing so, the Current Methodology also ignores the value of long-term resources, such as hedge value, optionality value and the value of avoiding RA and RPS compliance penalties. While it understates portfolio value, the Current Methodology *overstates the costs* of the Joint Utilities’ portfolios that must be shared with CCA

³¹ Cal. Pub. Util. Code §367.

³² *Id.* §366.2(g).

³³ *Id.* §366.2(f)(2).

³⁴ Ex. IOU-1 at 2-10.

³⁵ Exh. CalCCA-1 at 2B-11:17-19.

³⁶ *Id.* at 2B-9:5-7.

³⁷ *Id.* at 2B-10:1-2.

customers to prevent cost shifts. It includes hundreds of millions of dollars annually of uneconomic costs of Legacy UOG –\$545 million for PG&E and \$270 million for SCE in 2018 alone – that are not within the statutory scope of cost responsibility for CCAs.³⁸

Changes to the Current Methodology are required to correct this significant cost shift. CalCCA proposes corrections to the Current Methodology that will result in a more reasonably representative portfolio valuation and align the scope of PCIA-eligible portfolio costs with Legislative directives.

2. The Commission Must Preserve CCAs' Rights to Be Solely Responsible for Procurement on Behalf of Their Customers.

In addition to preventing cost shifts, the Commission must preserve the rights of CCAs to be “solely responsible” for procurement on behalf of their customers, unless the Legislature has otherwise authorized.³⁹ The Scoping Memo expressly recognizes these rights, providing that solutions in this proceeding “should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law.”⁴⁰ The Joint Utilities’ Green Allocation Mechanism and Portfolio Monetization Mechanism (GAM/PMM) proposal threatens the Commission’s ability to fulfill this statutory directive. The GAM/PMM would force portfolio attributes into CCA portfolios, regardless of a CCA’s need or procurement strategy, leaving CCAs little or no ability to trade the products in the market without a loss of value. This involuntary product allocation is not authorized by statute and would materially impede a CCA’s statutory right to be “solely responsible” for procurement on behalf of its customers.⁴¹

³⁸ Exh. CalCCA-1 at 2B-21, Table 2B-1, Exh. CalCCA-3 at 7-9: fn. 126.

³⁹ Cal. Pub. Util. Code §366.2(a)(5).

⁴⁰ Scoping Memo, Guiding Principle 1.f. at 14.

⁴¹ See *infra* Section III.

CalCCA acknowledges that a solution is required to address the growing mismatch between bundled utility portfolio resources and bundled load, as CCA load grows. CalCCA proposes a Staggered Portfolio Auction, which will allow *voluntary, market-based* redistribution of portfolio resources by the end of 2021, enabling ESPs, CCAs and the Joint Utilities to create a portfolio that meets the needs of their customers. Adoption of this proposal would allow the Commission to meet its statutory obligations to preserve CCAs' rights to autonomy in building their portfolios.

3. The Commission Must Prevent the Utilities from Using Their Dominance to Undermine CCA Development or Operation and Ensure Fair Competition between the Joint Utilities and Other LSEs.

To fulfill the Legislature's vision for CCAs and the Commission's own commitments to preserve fair competition among LSEs,⁴² the Commission must prevent the use of utility dominance to undermine CCA development or operation. The GAM/PMM, however would allow the utilities, in the face of substantial declines in load, to continue to maintain ownership, control and sole access to critical market information for the portfolio resources used to serve their competitors' customers. It would thus reinforce utility dominance and market power, creating an undue advantage to bundled utility customers over customers of a CCA.

CalCCA's proposal mitigates the potential for the misuse of the Joint Utilities' position to the disadvantage of the customers of other LSEs. Rather than permitting the Joint Utilities to continue to retain supply portfolios far in excess of their bundled needs, the Staggered Portfolio Auction allows the realignment of bundled supply and demand. The SPA allocates not only the short-term use of a portfolio resource, as proposed by the Joint Utilities, but long-term control

⁴² SB 790 at §2(h).

and potential ownership of the resources.⁴³

4. The Commission Must Ensure Just and Reasonable Rates

Beyond cost allocation and supply distribution, this rulemaking implicates the Commission’s overall responsibility to ensure just and reasonable rates. The Public Utilities Code permits the Commission to allocate to CCA departing load only the “unavoidable” costs of the utility portfolio, excluding costs that are avoidable.⁴⁴ While not similarly articulated in statute for bundled or DA customers, no reasonable rate for any customer should include “avoidable” costs. Consequently, the Commission must ensure that the utilities minimize portfolio costs for all customers and exclude avoidable costs from recovery through the PCIA.

CalCCA alone has provided proposals in this proceeding aimed to reduce costs where avoidable, including securitization of UOG rate base⁴⁵ and buydown and securitization of long-term PPAs.⁴⁶ CalCCA further has proposed measures to prevent the increase of the existing uneconomic cost problem, improving departing load forecasting, modifying procurement practices and more actively managing portfolios.⁴⁷

B. CalCCA Proposes a Phased Transition Plan to Allocate Uneconomic Costs and Accommodate Future CCA Growth Consistent with the Commission’s Statutory Obligations

The magnitude and complexity of the coming changes in the procurement market require a comprehensive solution consistent with governing statutes. CalCCA proposes a phased solution, correcting the Current Methodology in the near term and transitioning over the next 2-3 years to a more durable framework for the future.

⁴³ See *infra* Section VII.B.2.

⁴⁴ Cal. Pub. Util. Code § 366.2(f)(2).

⁴⁵ See *infra* Section X.

⁴⁶ *Id.*

⁴⁷ See *infra* Section IX.A.

In the near term, the Commission must mitigate the cost shift under the Current Methodology. CalCCA proposes to mitigate the existing cost shift from bundled to departing load customers by correcting the administratively determined benchmark employed by the Current Methodology to better reflect the scope and characteristics of portfolio cost and value (Corrected Methodology). Several changes must be made to correct the value side of the equation:

- ✓ Replace the current short-term capacity value with a Commission-adopted long-term resource value;⁴⁸
- ✓ Add a component to account for the value of GHG-free resources not currently reflected in the benchmark;⁴⁹
- ✓ Add a component to account for the value of ancillary services value not currently reflected in the benchmark.⁵⁰

CalCCA also proposes minor modification of the Green Adder to remove the outdated DOE value component.⁵¹ To correct the cost side of the uneconomic cost equation, CalCCA proposes removing Legacy UOG costs from CCA cost responsibility.⁵²

The Corrected Methodology should remain in place until the Staggered Portfolio Auction (SPA) can be implemented. The SPA would replace the value measures for GHG-free and RPS resources; the Corrected Methodology would remain in place for fossil resources until they are no longer included in the PCIA-eligible portfolio. The SPA would require the Joint Utilities to offer all RPS-eligible and GHG-free resources into the market on a long-term basis through eight quarterly auctions, beginning on January 1, 2020. The Joint Utilities, CCAs, ESPs and other market participants would voluntarily purchase resources in the auction, choosing the products

⁴⁸ See *infra* Section VII.A.1. at 50.

⁴⁹ See *infra* Section VII.A.2. at 59.

⁵⁰ See *infra* Section VII.A.3. at 60.

⁵¹ See *infra* Section VII.A.4. at 63.

⁵² See *infra* Section V.A.4. at 33.

they need to meet their customers' needs. The SPA thus would ensure voluntary redistribution of utility portfolio resources and generate more reasonably representative market prices to draw boundary between uneconomic and economic portfolio costs.

As the short- and long-term changes are being implemented, the Commission should also direct the utilities to embark on a serious campaign to reduce their overall portfolio costs. First, the utilities should be strongly encouraged to securitize all of their UOG assets, lowering the costs of financing; in the first year, this would reduce portfolio costs by \$496 million for PG&E and \$131 million for SCE.⁵³ Over the 20-year term of a securitization bond issuance, the benefits have a net present value of \$1.3 billion for PG&E and \$589 million for SCE.⁵⁴

Changes to portfolio management may also prevent further accumulation of uneconomic portfolio costs. CalCCA recommends modifications to the Joint Utilities' forecasting practices to better account for departing load. CalCCA also recommends improvements in the Joint Utilities' portfolio management practices:

- ✓ Requiring more active management of the portfolio in response to departing load;
- ✓ Prohibiting practices aimed to protect bundled ratepayers at departing load customers' expense; and
- ✓ Requiring optimization of sales from the Joint Utilities' portfolios to capture the full value of the resources for all customers.

These changes will reduce and more equitably allocate PCIA-eligible costs.

In addition to a transition plan to address utility portfolio costs, allocation and supply redistribution, CalCCA offers several additional proposals:

- ✓ Permit prepayment of uneconomic cost responsibility by CCAs and ESPs on behalf of their customers;

⁵³ See *infra* Section X.C.; Exh. CalCCA-1 at 2A-16, Figure 2A-4 and 2A-17, Figure 2A-5.

⁵⁴ Exh. CalCCA-1 at 3-7:7-9

- ✓ Modify vintaging rules to ensure that departing load customers are not saddled with the costs of contracts that are not reasonably “attributable to” those customers;
- ✓ Maximize the availability of information to CCAs and ESPs in the ERRA proceedings to facilitate long-term PCIA forecasts.
- ✓ Require the Joint Utilities to present uneconomic portfolio costs as a separate line item on bundled customer bills to better align customer understanding of the rates they pay.

Adoption of these proposals will enable the Commission to fulfill its statutory role and the Guiding Principles established by the Scoping Memo.

II. BACKGROUND (Common Outline §I)

The PCIA has its roots in the efforts of the Legislature and the Commission to transition the State to a competitive electricity market, which efforts were interrupted by the California energy crisis of 2000-2001. In 1996, the Legislature enacted Assembly Bill 1890, which contemplated the possibility of utility divestiture of generation assets⁵⁵ and anticipated a full transition to a competitive market by 2002.⁵⁶ AB 1890 created a nonbypassable charge to be paid by all electricity customers, regardless of supplier, that was designed to allow the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition.⁵⁷ The charge was implemented by the Commission as the “Competition Transition Charge.” The Commission intended to transition to full competition “as

⁵⁵ See Cal. Pub. Util. Code §367(b).

⁵⁶ AB 1890, *supra*, § 1(b) (“It is the further intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following: (1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations....”).

⁵⁷ Cal. Pub. Util. Code §367.

quickly as possible so that full competition can begin with minimal market distortions.”⁵⁸ In fact, the Commission intended that the collection of the CTC would be completed by 2005.⁵⁹

The PCIA that is in place today is based on a concept established during the energy crisis. At that time, due to a rapid and unforeseen shortage of available electric power, the Legislature authorized the California Department of Water Resources (CDWR) to enter into contracts for the purchase of electric power for delivery to retail customers of PG&E, SCE and SDG&E.⁶⁰ CDWR did so, purchasing energy on behalf of all customers, bundled service and DA customers alike. The Legislature also directed the Commission to suspend the right of customers to enter into direct access arrangements with non-IOU providers of electricity.⁶¹

The Commission determined that in order to avoid a cost-shifting effect, DA customers should be required to pay a portion of costs that were incurred by the State during the crisis on behalf of all retail end use customers in the service territories of the three utilities.⁶² The Commission adopted a “cost responsibility surcharge” methodology,⁶³ which incorporated a “DWR Power Charge” aimed to determine the uneconomic cost of the CDWR long-term contracts on an annual basis.⁶⁴ Relying in part on the Commission’s general ratemaking authority under Sections 701, 451, and 453, the Commission also adopted a “separate charge to cover the ongoing above-market portion of utility-related generation costs,” allowing for the

⁵⁸ D.95-12-063, 64 CPUC 2d 1 at 60.

⁵⁹ *Id.* at 58.

⁶⁰ AB 1X, *supra*

⁶¹ *Id.*

⁶² D.02-03-055, Finding of Fact 3.

⁶³ D. 02-03-055, Ordering Paragraph 3, as modified by D.02-04-067.

⁶⁴ D.02-11-022 at 3-4.

netting of above-market CDWR and then-below-market Legacy UOG costs in the utility portfolio.⁶⁵

To calculate these components, the Commission adopted a “DA In – DA Out” methodology to determine the increase in the average generation cost to the bundled service customers as the result of the departure of some customers to DA service. The CRS could then be calculated as a charge to DA customers required to maintain a steady average rate for generation for bundled customers. This model was later amended by replacing the market prices used in the calculation with an administratively determined “marked price benchmark” (MPB).⁶⁶

Also in 2002, the Legislature authorized Community Choice Aggregation through the enactment of Assembly Bill 117. Once again the Legislature sought to prevent cost shifts between bundled and departing customers.⁶⁷ AB 117 expressly required CCA customers to bear cost responsibility for CDWR historical purchases and the long-term contracts negotiated by CDWR during the energy crisis, via the “DWR Bond Charge”⁶⁸ and a “DWR Power Charge,”⁶⁹ respectively. In addition, the Legislature required CCA customers to reimburse the utility for certain balancing accounts⁷⁰ and “[a]ny additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer.”⁷¹

⁶⁵ *Id.* at 4.

⁶⁶ D.06-07-030. Although the methods for calculating the CRS were determined and adopted by the Commission for DA and CG departing load in R.02-11-011, they were also adopted for calculation of CCAs’ CRS in R.03-10-003 (see D.04-12-046 and D.07-01-025).

⁶⁷ Cal. Pub. Util. Code §366.2(c)(5), (d)(1).

⁶⁸ *Id.* §366.2(e)(1). The long-term contracts have since terminated.

⁶⁹ *Id.* §366.2(e)(2).

⁷⁰ *Id.* §366.2(f)(1) (“the electrical corporation’s unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.”).

⁷¹ *Id.* §366.2(f)(2).

Drawing from prior nonbypassable charge decisions and models developed for DA CRS, the Commission implemented AB 117 through Decision 04-12-046, and adopted a Cost Responsibility Surcharge model for CCA customers. (Although the Commission adopted the previously established methodology developed within the DA context, it is not apparent that efforts were made to ensure the methodology aligned with the specific language of AB 117, which envisioned an entirely distinct form of departing load.) Later on the Commission expanded the CRS in D.04-12-048, including provisions for new or long-term resources used by the utilities to ensure reliability or RPS compliance. The Commission concluded that “the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers.”⁷²

In 2006, the Commission folded the indifference calculations for the DWR Power Charge and Legacy UOG together into the “Power Charge Indifference Adjustment,” which was originally designed for DA.⁷³ The methodology employed to calculate the charge is very similar to what we have today. The PCIA was intended to recover, on an annual basis, the difference between a revised benchmark power cost and “the average cost of the utilities’ total portfolio, including both utility retained generation power and allocated DWR power costs, to determine the level of the indifference charge for each year.”⁷⁴ The 2006 decision also added a capacity value in the indifference calculation, which had until then been based solely on energy costs.⁷⁵

Nearly four years after full Commission implementation of CCA, in 2010 Marin Clean Energy became the first CCA to begin service. The Commission and Legislature attributed the

⁷² D.04-12-048 at 60.

⁷³ D.06-07-030 at 7. The decision referred to the changes as the “Prospective DA CRS Market Benchmark Methodology Revisions.”

⁷⁴ *Id.*, Ordering Paragraph 6.

⁷⁵ *Id.* at 9-10.

slow launch of CCAs, in part, to activities by the investor owned utilities. PG&E’s highly disruptive behavior, in particular, led to legislative and Commission action to prevent IOUs from engaging in costly and often misleading campaigns against CCAs at the expense of their own bundled customers.⁷⁶ A code of conduct for utility interactions with CCAs was established in 2012, via D.12-12-036. As of today, 20 CCAs are operational or near-operational.⁷⁷

The MPB and the Current Methodology were last significantly modified in D.11-12-018, prior to the establishment of all but one of the current CCAs. At that time, the Commission determined to increase the MPB by an “RPS adder” to recognize the establishment of renewable procurement standard requirements, and the fact that contracts executed to satisfy the RPS requirements would be relatively more expensive than other conventional generation.⁷⁸ The Commission also adopted a “capacity adder” which was set as the going-forward costs of a simple cycle combustion turbine, to be updated biannually.⁷⁹ The scope of CCA and DA cost responsibility increased in 2014, when the Commission authorized the recovery of the utilities’ energy storage procurement costs through the PCIA.⁸⁰

Although the parties to this proceeding may not necessarily agree on the specific causes for the current situation, and although they disagree on the means of resolving the issues raised here, they all agree that the current PCIA and its methodology do not achieve the compliance with statutory scheme authorizing CCA formation.

⁷⁶ Cal. Pub. Util. Code §707; SB 790, *supra*, § 2(d).

⁷⁷ A table showing existing CCAs and their original launch dates is provided as Exhibit 1-A.

⁷⁸ Specifically, as described in D.11-12-018, the RPS adder is to be calculated as the weighted average of DOE data for premiums paid by customers under voluntary green pricing programs (32%) and the premium paid by the Joint Utilities for renewable resources delivered in the year when the CRS is calculated and the prior year (68%).

⁷⁹ D.11-12-018 at 30.

⁸⁰ *Id.* at 22.

III. THE LEGISLATURE HAS CREATED A ROADMAP FOR ASSESSING AND REFINING THE CURRENT METHODOLOGY (Common Outline §I)

The Public Utilities Code provides a clear roadmap for resolving the issues raised in this proceeding. First, the law requires the Commission to avoid “cost shifts” among customer classes. AB 117 provided explicit guidance on the categories of costs that must be recovered from CCA departing load customers to prevent cost shifts to bundled customers. SB 350 also required the Commission to prevent the costs of procurement under the Integrated Resource Plan program from being shifted between bundled and departing load customers. Second, while the law permits the allocation of specific costs to CCA departing customers, it narrowly limits the ability of a utility to go beyond that scope and interfere with a CCA’s procurement strategy. SB 790 granted CCAs full procurement autonomy in serving their customers, except where specifically authorized by statute. The Commission must keep these statutory guidance firmly in mind when addressing the many complex issues raised in this rulemaking.

A. The Legislature Has Specifically Identified the Procurement Costs that Must Be Allocated to Prevent Cost Shifts

In authorizing the formation of CCAs in 2002, the Commission mandated a “cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs....”⁸¹ Those specified subdivisions required CCA departing load customers to bear responsibility for several specific categories of costs:

- Department of Water Resources bond charges⁸²
- “Department of Water Resources’ estimated net unavoidable electricity purchase contract costs”⁸³

⁸¹ Cal. Pub. Util. Code §366.2(c)(5).

⁸² *Id.* §366.2(e)(1).

- “[U]nrecovered past undercollections for electricity purchases, including any financing costs”⁸⁴
- A CCA customer’s “share of the electrical corporation’s *estimated net unavoidable electricity purchase contract costs attributable to the customer*”⁸⁵

The Legislature further provided that the customer’s cost share “shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.”⁸⁶

The Legislature next spoke on the issue of CCA cost shifts in 2005, enacting a resource adequacy mandate to be applied to all LSEs, including CCAs. Section 380(b)(2) requires the Commission to “[e]quitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.”⁸⁷ The Legislature provided the Commission flexibility in achieving this goal to “consider a centralized resource adequacy mechanism among other options,”⁸⁸ which was the root of the Cost Allocation Mechanism adopted in D.06-07-029. At the same time, the Legislature made clear that CCAs “shall be subject to the same requirements for resource adequacy” as other LSEs and reiterated their obligations under the Renewables Portfolio Standard program.⁸⁹ It addressed RA again in 2009, making clear the responsibility of CCAs and other LSEs to bear responsibility for resources contracted by the utility for reliability purposes.⁹⁰

⁸³ *Id.* §366.2(e)(2).

⁸⁴ *Id.* §366.2(f)(1).

⁸⁵ *Id.* §366.2(f)(2).

⁸⁶ *Id.* §366.2(g).

⁸⁷ *Id.* §380(b)(2).

⁸⁸ *Id.* §380(h).

⁸⁹ *Id.* §380(e). CCAs have carried the same RPS compliance obligations as other LSEs since the program was first enacted in 2002. *See* SB 1078; §399.12(b)(2).

⁹⁰ *Id.* §365.1.

Cost shifting was also addressed in 2011 in the enactment of SB 790. While leaving the categories of cost responsibility for CCA departing load customers unchanged, the Legislature directed that “[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.”⁹¹ The Legislature thus clarified that the prohibition on cost shifting goes both directions.

Most recently, in 2015, the Legislature again addressed cost shifting in adopting the requirement for LSEs to submit IRPs. The statute requires:

To the extent that *additional* procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5,⁹² the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is *no cost-shifting* among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.⁹³

It further clarifies that the prohibition on cost shifting goes both ways:

Bundled retail customers of an electrical corporation shall not experience any cost increase⁹⁴ as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.⁹⁵

The statute also provides that “the net costs of any *incremental* renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a)

⁹¹ *Id.* §366.2(a)(4).

⁹² Assembly Bill 57 (Stats. 2002, ch. 835). AB 57, which enacted the procurement planning process in §454.5, contained no provisions on cost shifting or cost allocation to customers of other LSEs.

⁹³ *Id.* §454.52(c) (emphasis supplied).

⁹⁴ “Cost increase,” set in the context of 20 years of cost shift statutes and Commission decisions, can only be understood to mean and increase in cost, net of benefits.

⁹⁵ *Id.* §366.3.

are allocated on a fully nonbypassable basis consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1.”⁹⁶

Through this roadmap, the Legislature has carefully framed and limited the scope of responsibility that must be borne by CCA departing load customers to prevent cost shifts.

- Commencing in 2002 with AB 117, a CCA customer departing utility service bears responsibility for “unrecovered past undercollections for electricity purchases” and the “estimated net unavoidable electricity purchase contract costs attributable to the customer.”
- The Legislature added certain resource adequacy generation costs in 2005.
- Finally, commencing in 2015, the Legislature placed on these customers the costs of *incremental* renewable integration resources procured by the utility through a centralized process, subject to the CCA’s right to self-provide, and the costs of *additional* procurement under the utilities’ bundled procurement plans or IRPs.

The Legislature has not authorized the inclusion of other types of procurement costs – notably Legacy UOG costs – nor has it authorized the allocation of products or benefits from the portfolio, other than certain RA resources, to CCAs.

B. The Legislature Granted CCAs the Sole Right to Procure Resources on Behalf of Their Customers, Subject Only to Exceptions Specified by Statute

The Legislature granted CCAs the sole right to procure resources on behalf of their customers. Following the battle for CCA implementation by the Marin Energy Authority (now Marin Clean Energy), the Legislature saw the need for CCA protections to prevent the utilities from impairing CCA formation. Bill analysis observed that a “genesis of this bill has been PG&E’s atrocious behavior surrounding the establishment of the Marin Energy Authority and its

⁹⁶ *Id.* §454.51(c) (emphasis supplied).

CCA program Marin Clean Energy.”⁹⁷ In enacting the Charles McGlashan Community Choice Aggregation Act (SB 790), the Legislature made several very important findings:

- (a) It is the policy of the State to provide for the consideration, formation, and implementation of community choice aggregation programs authorized in Section 366.2 of the Public Utilities Code.

* * * *

- (c) Electrical corporations have inherent market power derived from, among other things, name recognition among customers, longstanding relationships with customers, joint control over regulated operations and competitive generation services, access to competitive customer information, and the potential to cross-subsidize competitive generation services.

- (d) The Public Utilities Commission has found that conduct by electrical corporations to oppose community choice aggregation programs has had the effect of causing community choice aggregation programs to be abandoned.

* * * *

- (f) The exercise of market power by electrical corporations is a deterrent to the consideration, development, and implementation of community choice aggregation programs.

- (g) California has a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs.

- (h) It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers.

⁹⁷ Senate Floor Analysis, September 9, 2011 at 5
https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201120120SB790.

In response, the Legislature directed the Commission to develop a code of conduct “to govern the conduct of the electrical corporations relative to the consideration, formation, and implementation of community choice aggregation programs....”⁹⁸ Importantly, it also provided that “[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*.”⁹⁹

Consequently, while the Legislature has clearly authorized CCA departing load customers’ responsibility for their share of certain *costs*, it has not granted the utility *carte blanche* to allocate *products or attributes* to the CCAs. While Section 366.2(g) contemplates a how to address cost responsibility if customers receive benefits from the portfolio, it does not *authorize* an allocation of attributes or products. In only one instance – resource adequacy¹⁰⁰ – does a statute contemplate the potential allocation of *products or attributes* to a CCA. Thus, CalCCA’s proposed solution in this proceeding is confined, as required by law, to *cost* allocation. The allocation of products or attributes, as proposed by the Joint Utilities, does not comport with this requirement.

IV. THE CURRENT METHODOLOGY SHIFTS COSTS FROM BUNDLED CUSTOMERS TO DEPARTING LOAD CUSTOMERS (Common Outline §III)

The first two issues in the Scoping Memo focus on whether the Current Methodology results in a cost shift between bundled and departing load customers.¹⁰¹ CalCCA provided direct testimony regarding these issues, acknowledging that a cost shift assessment is highly sensitive to assumptions and that clear, accurate market value measures are not readily available for all

⁹⁸ Cal. Pub. Util. Code §707.

⁹⁹ *Id.* §366.2(a)(5).

¹⁰⁰ *Id.* §380(h).

¹⁰¹ Scoping Memo at 20.

portfolio products. CalCCA nonetheless concludes, given the substantial differences produced by other Commission-approved value measures, that the Current Methodology's portfolio value measures are too low. The result is an annual PCIA that is too high and shifts costs from bundled to departing load customers.¹⁰²

CalCCA observes two primary problems with the Current Methodology's portfolio value measures as expressed in the benchmark. First, the Current Methodology does not recognize and value all products and attributes in the utilities' portfolios. Most notably, it does not distinguish between different types of resource adequacy products,¹⁰³ it does not reflect a value for GHG-free energy¹⁰⁴ and it does not reflect a value for ancillary services.¹⁰⁵ Moreover, the Current Methodology undervalues portfolio capacity by using a short-term proxy value derived solely from power plant operational costs for System RA only.¹⁰⁶ CalCCA also observes that values for these products are not easily divined, which CalCCA illustrates by identifying the range of different economic values the Commission uses for capacity, ancillary services, avoided GHG and avoided RPS costs, as shown in Table 2A-3.¹⁰⁷

¹⁰² Exh. CalCCA-1 at 2A-12-17.

¹⁰³ Exh. CalCCA-1 at 2B-6:18-22.

¹⁰⁴ *Id.* at 2B-10-11.

¹⁰⁵ *Id.* at 2B-9-10.

¹⁰⁶ *Id.* at 2B-7-9.

¹⁰⁷ *Id.* at 2A-11.

Table 2A-3

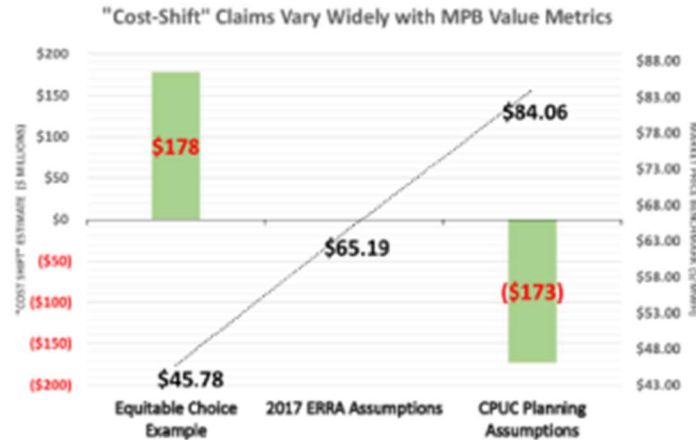
Comparison to Marginal Cost/Market Values Indicators Across CPUC/CEC Proceedings									
Proceeding	Utility / Region	Model / Source	Capacity \$ /kW-Yr	Energy \$/MWH	Ancillary Service \$/MWH	RPS Cost \$/MWH	RPS Premium \$/MWH	GHG Value \$/tonne	GHG Value \$/MWH
PG&E 2018 ERRA	PG&E	ERRA Table 9.5	\$58.27	\$33.77		\$61.47	\$24.16		
SCE 2018 ERRA	SCE	ERRA WPs	\$58.27	\$32.37		\$61.47	\$25.11		
PG&E 2017 GRC	PG&E	MC/RA WPs	\$28.64	\$28.30					
SCE 2018 GRC	SCE	MC/RA WPs	\$146.85	\$36.81					
EE / DRP / UEE / NEM / DG	North	E3 Avoided Cost	\$113.74	\$28.03		\$79.90	\$14.17	\$66.37	\$29.15
	South	Calculator	\$109.75	\$28.06		\$79.90	\$14.17	\$66.37	\$29.15
CEC Title 24	SF CZ 3	2016 TDV Update Model	\$145.75	\$37.75	\$0.19	\$126.00	\$19.50	\$15.72	\$9.43
	Fresno CZ 12		\$130.54	\$37.75	\$0.19	\$129.90	\$19.50	\$15.72	\$9.43
	LA/SD--CZ 7		\$105.70	\$38.01	\$0.19	\$129.90	\$19.50	\$15.72	\$10.31
	LA/SD--CZ 10		\$145.58	\$38.01	\$0.19	\$129.90	\$19.50	\$15.72	\$10.31
DCPP Retirement	PG&E	DCPP WPs				\$85.62			
CAISO	CAISO	2017 MMC	\$74.28	\$32.97	\$0.54			\$12.83	\$5.45

Simply substituting two of the value measures in the Current Methodology for 2017 – capacity and the Green Adder – with the comparable value measures from the Commission’s Avoided Cost Calculator, suggests that \$173 million annually is being shifted from PG&E’s bundled to departing load customers.¹⁰⁸ This conclusion flips on its head PG&E’s conclusions supporting its Equitable Energy Choice for Californians claims that \$178 million was shifted from departing load customers to bundled customers during the same period.¹⁰⁹ The differences are illustrated in Figure 2A-1:

¹⁰⁸ Exh. CalCCA-1 at 2A-11-12.

¹⁰⁹ See Exh. CalCCA-100, Equitable Energy Choice for Californians, Fact Sheet (concluding that “some customers who now receive power through an alternative energy provider may on average only pay roughly 65% of the cost of clean energy that was purchased on their behalf.”). PG&E was involved in the formation of EECC and had a role in estimating the cost shift described on the fact sheet. 1 Tr. 69:10 – 70:8.

Figure 2A-1



Taking this analysis one step further, adjusting the Current Methodology to reflect all of CalCCA’s proposed refinements to value measures,¹¹⁰ produces an even greater cost shift from bundled to departing load customers. Assuming that departing load constitutes 40.9% of PG&E’s service territory load and making a simplifying assumption that cost allocation to various customers is proportional to load share, CalCCA estimates that departing load customers in 2018 will pay PCIA costs that are roughly \$492 million (54%) greater than the costs that are reasonably attributable to them.¹¹¹ Assuming that departing load constitutes 3.9% of SCE’s service territory load, CalCCA estimates that departing load customers in 2018 will pay PCIA costs that are roughly \$25 million (53%) greater than the costs that are reasonably attributable to them.¹¹²

¹¹⁰ The calculations compare the 2018 ERRR results for each utility with a scenario that adjusts the value measure for capacity, removes the DOE element of the RPS value measure, adds a GHG-free value and adds an ancillary service value; the scenario also excludes PG&E’s Humboldt costs and SCE’s Pebbly Beach costs as inappropriately included in the scope of PCIA-eligible costs. The scenario does not net the benefits of securitization, which would accrue to all bundled and departing load customers. See Exh. CalCCA-1, Figure 2A-4 at 2A-16 and Figure 2A-5 at 2A-17.

¹¹¹ See Exh. CalCCA-1, Figure 2A-4 at 2A-16, $\$492,155 / (\$1,204,596 * .409)$.

¹¹² See Exh. CalCCA-1, Figure 2A-5 at 2A-17, $\$25,411 / (\$646,677 * .039)$.

Beyond the changes in portfolio value measures, the scope of costs attributed to CCA customers in the PCIA calculation is materially broader than contemplated by statute. As discussed in Section III above, the Legislature has defined the scope of costs that may be recovered from CCA departing load customers to prevent cost shifts to bundled customers.¹¹³ Most notably, as discussed in Section V below, the Legislature did not contemplate recovery from these customers of the utilities' Legacy UOG costs.¹¹⁴ CalCCA estimates that for 2018, PG&E's PCIA included \$545 million in uneconomic Legacy UOG costs.¹¹⁵ Based on the same simplified assumption that cost allocation is proportional to load share, CCA departing load's share of those costs – 40.9% – represents a \$222 million overpayment to bundled customers.¹¹⁶

The Joint Utilities provided no direct testimony addressing cost shifts under the Current Methodology, despite PG&E's role in presenting cost shift estimates publicly through the Equitable Energy Choice for Californians website and public campaigns.¹¹⁷ Only in rebuttal was any attempt made to quantify a cost shift under the Current Methodology, and only PG&E performed this calculation.¹¹⁸ While also acknowledging the difficulty in identifying value

¹¹³ See *supra* at 16.

¹¹⁴ See *infra* at 28.

¹¹⁵ Exh. CalCCA-1 at 2B-21, Table 2B-1.

¹¹⁶ Note that the \$222 million cost shift from Legacy UOG is not additive to the \$492 million cost shift from refined valuation benchmarks since the two calculations overlap in terms of the resources being valued and the benchmarks being used to value them. However, this comparison does illustrate that roughly 45% of CalCCA's asserted cost shift (\$222 million / \$492 million = 45%) is validated simply by recognizing that recovery of Legacy UOG costs is unauthorized and inappropriate.

¹¹⁷ See Exh. CalCCA-100, Equitable Energy Choice for Californians, Fact Sheet (concluding that "some customers who now receive power through an alternative energy provider may on average only pay roughly 65% of the cost of clean energy that was purchased on their behalf."). PG&E was involved in the formation of EECC and had a role in estimating the cost shift described on the fact sheet. 1 Tr. 69:10 – 70:8.

¹¹⁸ Exh. IOU-3 at 2-35:16-30.

measures for all products and attributes – particularly capacity value¹¹⁹ – PG&E concludes that a cost shift is occurring in the opposite direction, from departing load to bundled customers. In other words, the portfolio value measures are, in PG&E’s view, too high and the PCIA is too low.

PG&E estimates that in 2018, a cost shift between \$190 million and \$259 million is occurring from departing load to bundled customers.¹²⁰ The estimates rely on two downward changes to value measures under the Current Methodology. Even the low end of PG&E’s cost-shift estimate lacks credibility.

PG&E replaces the short-run reliability adder value for 2018 (\$58.27/kW-year) with the 2016 RA Report NP-26 Average Value for short-term sales of excess capacity.¹²¹ As explained in Section VII.A.1, this value is unreliable because it not only excludes any long-term capacity value, but because it relies data representing only 20% of the RA capacity in the market.¹²² In essence, PG&E is simply using the wrong product as a proxy. PG&E’s use of this adder also ignores the Joint Utilities testimony that there is no available market price that measures the full value of capacity.¹²³

PG&E replaces the Green Adder with an alternative value, using the “Mid-point of positive values from Figure 2-2 of the Joint Utilities Prepared Testimony.”¹²⁴ Again, this measure is wholly unreliable. First, the Joint Utilities acknowledge that the chart in Figure 2-2 is

¹¹⁹ Exh. IOU-1 at 5-9:21-23 (“Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”).

¹²⁰ Exh. IOU-3A AppE-1:74 and AppE-2:74.

¹²¹ *Id.* (referring to Exh. CalCCA-109, Table 7, NP-26 Average Price (\$kW/month)).

¹²² *See infra* at 50-51.

¹²³ Exh. IOU-1 at 5-9:21-23 (“Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”).

¹²⁴ Exh. IOU-3A AppE-1 and AppE-2:74.

“not intended to be exhaustive.”¹²⁵ Second, there is no way to know whether this chart fairly represents the broader range of transactions in the market, particularly because the table, on its face, does not include any transactions in which one of the Joint Utilities is a counterparty. Third, all of the transactions shown in the table indicate that they are transactions for solar resources, with the exception of one wind project. Finally, even a one-year REC product, represented by the 2018 PCC 1 REC index published by *Platt’s*, is \$16/MWh¹²⁶ – materially more than the \$11.50/MWh the Joint Utilities derive from Figure 2-2. And, as CalCCA noted in its rebuttal testimony, the *Platt’s* REC index does not reflect long-term value.¹²⁷

CalCCA acknowledges that there is no certain, precise way to measure the extent of any cost shift occurring under the Current Methodology. Directionally, however, the evidence demonstrates that it is far more likely that a cost shift is occurring from bundled to departing load customers than, as the utilities suggest, the other way around.

V. THE SCOPE OF COSTS THAT MAY BE ALLOCATED THROUGH THE PCIA IS LIMITED BY STATUTE AND PRIOR COMMISSION DECISIONS (Common Outline §IV)

A. Legacy Utility Owned Generation Costs Do Not Fall Within the Scope of Costs That Can Be Allocated to CCA Departing Load Customers

Substantial uneconomic costs of Legacy UOG – utility-owned generation installed before 2002 – are currently recovered from CCA departing load customers through the PCIA.¹²⁸

CalCCA estimates that (1) PG&E’s 2018 uneconomic Legacy UOG costs will total approximately \$545 million and (2) \$270 million in such costs for SCE.¹²⁹ The Joint Utilities

¹²⁵ Exh. IOU-3 at 2-11, n. 23.

¹²⁶ Exh. AD-1 at 17.

¹²⁷ Exh. CalCCA-3 at 2B-10:15-17.

¹²⁸ Exh. IOU-1 at 4-54, n. 81.

¹²⁹ Exh. CalCCA-3 at 7-9, n. 126.

propose to continue PCIA recovery of these costs from CCA customers¹³⁰ but, at the same time, exempt pre-2009 DA customers from paying these costs.¹³¹

The Joint Utilities proposal is unreasonable and unlawful. Legacy UOG costs, by statute, were intended to have been fully recovered by 2005.¹³² Moreover, while CCA customers maintain a legal responsibility for remaining CTC, the Legislature did not impose other Legacy UOG costs on CCA departing load customers.¹³³ In fact, non-CTC Legacy UOG costs crept into the PCIA in 2002 only to accommodate DA customers, as suggested by D.02-02-011. Continuing to impose uneconomic Legacy costs on CCAs, while exempting pre-2009 DA customers, is contrary to statutory direction concerning what costs are recoverable from CCAs. The Joint Utilities' proposal also discriminates against CCA and more recently departed DA customers.

1. State Law Does Not Require CCA Departing Load Customers to Pay for Legacy UOG Costs

Legacy UOG costs were originally intended to have been fully recovered by 2005 in the transition to retail competition. Assembly Bill 1890, enacted in 1996, contemplated the possibility of utility divestiture of generation assets¹³⁴ and anticipated a full transition to a competitive market by 2002.¹³⁵ The statute allowed the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition through a

¹³⁰

Id.

¹³¹ Exh. CalCCA-114 A.16-04-018, at 2-3.

¹³² D.95-12-063, 64 CPUC 2d 1 at 58.

¹³³ *See supra* at 17.

¹³⁴ *See* Pub. Util. Code §367(b). The Commission later found that divestiture was the “only structural option which will completely eliminate the utility’s ability to engage in improper cross-subsidization.” D.95-12-063 at 193.

¹³⁵ AB 1890, §1(b) (“It is the further intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following: (1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations....”).

nonbypassable charge to be paid by all electricity customers, regardless of supplier.¹³⁶ In implementing AB 1890, the Commission labeled this nonbypassable charge the “Competition Transition Charge” and observed that its goal was to “get through this transition period as quickly as possible so that full competition can begin with minimal market distortions.”¹³⁷ It concluded: “With the exception of CTC arising from existing contracts, *no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.*”¹³⁸ The utilities were given clear notice that California was transitioning and had a chance at that time to address uneconomic Legacy UOG.¹³⁹

Nothing in the governing statutory framework has changed to permit recovery of these costs from departing load customers outside of the CTC. Moreover, the Legislature made clear its intent *not* to recover the costs from CCA departing load customers in AB 117. As discussed in Section III.A, the Legislature carefully prescribed the scope of costs that must be recovered from CCA departing load to prevent a cost shift to bundled customers.¹⁴⁰ Because the statute was enacted in 2002, the Legislature necessarily was aware the utilities were continuing to operate Legacy UOG and understood the cost recovery provisions of AB 1890. The Legislature elected to include in the scope of CCA departing load cost only CDWR bond and power costs

¹³⁶ See Cal. Pub. Util. Code §367.

¹³⁷ D.95-12-063 at 119.

¹³⁸ *Id.* (emphasis supplied).

¹³⁹ See, e.g., D.95-12-063, 64 CPUC 2d, 1, 49 (“Our proposal contemplates a five-year transition period during which some utility generation assets will remain under the ownership of the utility and our regulations, while others will undergo a market valuation process and possible a transfer of ownership.”); Cal. Pub, Util. Code §367(b) and §390(c).

¹⁴⁰ See *supra* at 17.

and “electricity purchase contract” costs.¹⁴¹ No statute passed since that time has imposed the Legacy UOG costs on CCA or any other departing load customer class.

Expressio unius est exclusio alterius – “the expression of one thing implies the exclusion of others”¹⁴² – is a well-settled canon of statutory interpretation in California law, applied by both state and federal courts. In AB 117, the Legislature specified the costs that were to be borne by departing load customers. Under *expressio unius*, that list must necessarily be interpreted to be exclusive unless a contrary legislative intent is expressed in the statute or elsewhere.¹⁴³ Here, as noted above, there is no contrary legislative intent expressed elsewhere that would preclude the application of *expressio unius* in this case. On the contrary, the Legislature has made its position perfectly clear. Legacy UOG costs may not be recovered from CCA departing load.

2. The Inclusion of Legacy UOG Costs in the PCIA Was Unrelated to and Did Not Materially Benefit CCA Departing Load

If the Legislature did not permit continued recovery of non-CTC Legacy UOG costs, how did they find their way into the PCIA? The answer resides in the dynamics surrounding DA that arose from AB 1X. The inclusion of these costs was unrelated to CCA departing load and has provided little benefit to this class of customers over the years.

AB 1X, an urgency statute, enabled the CDWR to begin to procure resources to serve the utilities’ load following the energy crisis. The statute also suspended the rights to enter into DA transactions until the CDWR “no longer suppliers power hereunder.”¹⁴⁴ In D.01-09-060, the

¹⁴¹ Cal. Pub. Util. Code §366.2(e) and (f). The reasons for exclusion may lie in the opposition by bundled ratepayer advocates to allowing lower cost Legacy UOG to offset the DWR Power Charge costs.

¹⁴² *Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379.

¹⁴³ *Fields v. Eu* (1976) 18 Cal.3d 322, 332; *CPF Agency Corp. v. Sevel’s 24 Hour Towing Service* (2005) 132 Cal.App.4th 1034.

¹⁴⁴ Cal. Water Code §80110.

Commission implemented the AB 1X suspension, effective September 20, 2001.¹⁴⁵ The Commission provided notice, however, that it could modify the suspension date to preclude agreements entered into on or after July 1, 2001.¹⁴⁶ In D.02-03-055, the Commission elected to retain the suspension date of September 1 on policy grounds, finding:

California is better served by maintaining the September 20, 2001 direct access suspension date and by imposing a direct access surcharge or exit fee, in lieu of an earlier suspension, to recover DWR costs from direct access customers.¹⁴⁷

Later that year, the Commission considered proposals by CLECA and other parties that if DA customers took on the above-market costs of CDWR contracts, the costs should be offset by the benefits of lower cost Legacy UOG.¹⁴⁸ Residential ratepayers disagreed:

ORA objects to CLECA's indifference approach, arguing that the cost of URG resources are "off limits" to DA customers, but are dedicated to service of bundled customers.¹⁴⁹

The Commission ultimately adopted CLECA's recommendation in D.02-11-022, imposing the above-market costs of CDWR contracts on DA customers, counterbalanced by including lower cost Legacy UOG and an extension of the implementation date for the AB 1X suspension of DA.

The Commission reexamined the issue of including utility generation in departing load charges in D.08-09-012.¹⁵⁰ At the time D.02-11-022 and D.08-09-012 were issued, Legacy UOG were assumed to be "lower cost" than other resources, and therefore would have a mitigating or netting effect on overall departing load charges.¹⁵¹ This fact was acknowledged by PG&E,

¹⁴⁵ D.01-09-060 at 2.

¹⁴⁶ *Id.* at 8-9.

¹⁴⁷ D.02-03-055, Finding of Fact 6, at 30.

¹⁴⁸ D.02-11-022 at 23.

¹⁴⁹ *Id.*

¹⁵⁰ *See generally* D.08-09-012 at 49-52.

¹⁵¹ *See, e.g.,* D.08-09-012 at 49; n.52 (emphasis added) ("For purposes of this decision, 'pre-restructuring resources' refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained

which asserted that “departing customers should not receive the benefits of existing generation after they leave bundled service.”¹⁵² Based on the assumption that UOG would lower the overall departing load charge, the Commission adopted a total portfolio approach to the PCIA that not only considered “cost-shifting” from new resources but also allowed UOG resources to be “netted” against this cost-shift.¹⁵³

While DA customers may have benefitted from this netting in the early years, CCAs do not appear to have similarly benefitted. PG&E CCA load departing in 2010 received some benefit, with Legacy UOG costs offsetting other PCIA costs by \$429 million. Thereafter, however, Legacy UOG has been consistently uneconomic, contributing \$545 in uneconomic costs to PG&E’s 2018 PCIA.¹⁵⁴

3. Requiring CCA Customers to Continue to Bear Legacy UOG Cost Responsibility While Exempting Pre-2009 DA Customers Would Unlawfully Discriminate Against CCA Customers

AReM/DACC propose to “memorialize” the permanent exemption of Legacy UOG from the PCIA for pre-2009 vintage.¹⁵⁵ Other than present a review of the utilities’ actions in this regard, AReM/DACC have been unable to further explain their rationale underlying the exemption.¹⁵⁶ In light of these facts, it is reasonable to examine in this proceeding whether Legacy UOG costs should be excluded from the PCIA calculation for *all* departing load customers – not just pre-2009 DA customers.

generation (*i.e.*, hydro, coal and nuclear plants). Power from these resources *tends to be cheaper* when compared to the costs related to ongoing CTC, the DWR contracts and new generation.”).

¹⁵² D.08-09-012 at 49.

¹⁵³ See D.08-09-012 at 51 (*citing in part* D.02-11-022 at 25).

¹⁵⁴ Exh. CalCCA-3 at 7-13:13-16 and Exhibit 7-A.

¹⁵⁵ Exh. AD-1 at 33.

¹⁵⁶ *Id.* at 32; *see also* 3 Tr. 593:6-594:18 (Fulmer).

AReM/DACC explained that in “in 2016, PG&E ceased collecting a PCIA from pre-2009 vintage DA customers.”¹⁵⁷ An associated issue (retirement of PG&E’s negative indifference balance for pre-2009 customers) was deferred.¹⁵⁸ PG&E’s witness stated that the recovery of Legacy UOG costs ended with the expiration of CDWR contracts, pursuant to D.07-05-055.¹⁵⁹ While it is not entirely clear how the decision was meant to apply, it does provide that “[a]t the expiration of the DWR contract term, the applicability of the indifference requirement would also expire.”¹⁶⁰

AReM/DACC further observe that SDG&E “has no power generating resources in its pre-2009 Vintage” and that SCE has stipulated that the only SCE Legacy UOG costs that will be imposed on pre-2009 vintage DA customers are those associated with the San Onofre Nuclear Generating Station.¹⁶¹ SCE has proposed to remove Legacy UOG costs in the PCIA for pre-2009 vintage customers.¹⁶² As described by SCE, “[u]nder the Settlement Agreement ... pre-2002 Legacy UOG resource costs and their associated forecast generation output would be excluded from the PCIA calculation.”¹⁶³

While the record remains unclear, it appears that the rationale for the termination of Legacy UOG cost recovery from pre-2009 DA customers was to maintain symmetry between recovery of CDWR costs and the associated Legacy UOG cost offset. Once CDWR contracts

¹⁵⁷ *Id.* at 32:5-6.

¹⁵⁸ *See* D.15-12-022 at 23; Ordering Paragraph 5.

¹⁵⁹ 2 Tr. 385:2-16.

¹⁶⁰ D.07-05-055, Finding of Fact 14 at 27.

¹⁶¹ *Id.* at 32.

¹⁶² *See Motion for Approval of Settlement Agreement*, dated February 1, 2018 and filed in the so-called Consolidated ERRA Docket (A.16-04-018, A.16-05-001, and A.16-06-003) (PCIA Settlement Motion).

¹⁶³ PCIA Settlement Motion at 4, n.8. The sole exception to this proposal relates to SONGS; however, under a separate settlement before the Commission in I.12-10-013 *et al.*, SCE proposed to eliminate SONGS cost-recovery for purposes of the PCIA on or about December 19, 2017. *See Joint Motion for Adoption of Settlement Agreement*, dated January 30, 2018, at 5 filed in I.12-10-013 *et al.*

expired, there no longer was a need for offset. Whatever the rationale, there is no reason why other DA or CCA customers should remain on the hook for these costs, and the Joint Utilities have not attempted to explain the differences in treatment. The proposed discrimination is unjustified and violates §728, which requires the Commission to reject rates that are “discriminatory” or “preferential.”¹⁶⁴

4. The Recovery of Legacy UOG Costs Through the PCIA Should Be Discontinued

It is difficult, if not impossible, to understand why the utilities should be permitted to continue to recover Legacy UOG costs from CCA customers – or any departing load customers – going forward. The utilities should have recovered any uneconomic costs for these resources long ago, as contemplated by AB 1890. Moreover, the Legislature declined, knowing of the existence of these resources and costs, to include these resources in the scope of CCA cost responsibility in AB 117. Finally, the utilities seek to exempt pre-2009 DA customers from these costs, perhaps appropriately, and it would be discriminatory to continue to impose these costs on other departing load customers.

¹⁶⁴ Public Utilities Code Section 728 provides in relevant part “Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service, product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force.” In addition, *see Pacific Tel. & Tel. Co. v. Public Utilities Com.*, 62 Cal. 2d 634, 647 (1965) wherein the court stated “the primary purpose of the Public Utilities Act is to insure the public adequate service at reasonable rates without discrimination; and the commission has the power to prevent a utility from passing on to the ratepayers unreasonable costs for material and services by disallowing expenditures that the commission finds unreasonable.”

B. Post-2002 Utility Owned Generation Costs

1. Nothing Has Changed to Warrant Removal of the 10-Year Limitation on Recovery of Post-2002 UOG Costs Through the PCIA¹⁶⁵

The Joint Utilities propose to expand the scope of PCIA-eligible UOG by lifting the existing 10-year limit on allocation of post-2002 fossil generation costs to the PCIA.¹⁶⁶ The Commission has addressed and retained this limitation in three decisions. While the Commission has left the door ajar for further discussion under specific circumstances, the utilities' attempts to lift the limitation – 15 years after its first implementation – are unsupported by the record and unjustified.

The Commission first adopted the limit in 2003 in approving SCE's Mountainview Generating Station, based on a proposal offered by TURN.¹⁶⁷ Mountainview was presented as a "unique opportunity" by SCE, but opposed by ORA and TURN as a "unique burden."¹⁶⁸ TURN argued that "if Mountainview, Mohave, and direct access all converged simultaneously it could place bundled customers at serious risk of 'rate shock.'" ORA further argued that Mountainview would be "too costly to ratepayers since it will come on line before it is needed and will contribute to an oversupply of capacity."¹⁶⁹ The Commission adopted TURN's proposal to require departing load customers to pay the costs of these resources for 10 years so that "ratepayers are not over-burdened during the early years of the contract with stranded costs if all

¹⁶⁵ This discussion has been drawn largely from CalCCA-3, Chapter 5, without identification of direct quotations.

¹⁶⁶ Exh. IOU-1 at 5-8 to 5-10.

¹⁶⁷ D.03-12-059 at 35, Finding of Fact 22.

¹⁶⁸ *Id.* at 32.

¹⁶⁹ *Id.*

the power is not needed....”¹⁷⁰ The Commission’s decision did not authorize SCE to reopen cost allocation of this resource in later years.

The Commission applied this limitation more generally in its 2004 adoption of the utilities’ Long-Term Procurement Plans, extending it prospectively to all “fossil-fueled resources acquired by the utilities either directly or through contract.”¹⁷¹ It made clear that the limitation would apply to “utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation.”¹⁷² In the next paragraph, the Commission contemplated greater flexibility for commitments under PPAs. It stated:

As several parties have noted, limiting commitments for new resources to only ten years may still increase costs for captive ratepayers due to the need for the project developer to seek accelerated cost recovery for their investments rather than amortizing these investments over a longer period.¹⁷³

In describing these circumstances, the Commission said that it would “allow the utilities the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years.” At the same time, it made clear that a longer term stranded cost recovery would apply to renewable resources.¹⁷⁴

The Commission confirmed its position once again in 2008, retaining the 10-year limitation. The Commission explained:

[T]he utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of the 10-year period, we assume that the utilities would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period.¹⁷⁵

¹⁷⁰ *Id.* at 35.

¹⁷¹ D.04-12-048 at 61.

¹⁷² *Id.*

¹⁷³ *Id.*

¹⁷⁴ *Id.* at 63.

¹⁷⁵ D.08-09-012 at 54-55.

It further observed that the resources also may become more economic over time, suggesting that it would be to ratepayers benefit to hold those resources to lower total portfolio costs at a later date. It provided, however, that if the utilities “believe a cost recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests....”¹⁷⁶

Despite clear direction from the Commission, very narrowly limiting any extension of the 10-year recovery period for post-2002 UOG costs, the utilities have put forward a vague and unsupported proposal for *all* such costs to be carried forward. The utilities have provided no data on the impact of this proposal, nor do they even identify the plants at issue. Instead, they offer only generic arguments. First, “a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”¹⁷⁷ Second, “the level of potential load departure that the Joint Utilities face today is substantially higher than any load departure contemplated at the time the 10-year limit was adopted.”¹⁷⁸ In essence, they argue that they have not been able to anticipate or forecast load loss over the past 15 years, an exercise the Commission has repeatedly required the utilities to do. Neither argument supports the dramatic change in rules the Joint Utilities request.

As an initial matter, the 2003 and 2004 decisions contemplated modifying the 10-year rule in the applications for resources, on a case-by-case basis. They did not contemplate modifying the 10-year rule after resources were approved. Similarly, the 2008 decision referenced back to the earlier decisions, providing for recovery period extension “for specific non-RPS resources...under the provisions of D.04-12-048.”¹⁷⁹ Changing the rules of the game

¹⁷⁶ *Id.* at 55.
¹⁷⁷ Exh. IOU-1 at 5-9.
¹⁷⁸ *Id.* at 5-10.
¹⁷⁹ D.08-09-012 at 55.

entirely, many years after the resources were built, would fail to provide notice of the implications of departure, particularly for those customers who have already departed utility service. Under these circumstances, the Commission's adoption of the Joint Utilities' proposal would be unlawful and subject to legal challenge on appeal.

In addition to serious questions of timing and notice, the absence of a capacity market cannot justify the significant modifications the utilities request. There has been no transparent capacity market for the past 15 years – nothing has changed, yet the Joint Utilities have waited until now to raise this question. Moreover, the Commission's decisions were not based solely on the expectation that a capacity market would develop. As explicitly discussed in D.08-09-012 quoted above, the Commission also appropriately considered the utilities' obligations to reasonably forecast and plan for their load and the long-term value profile of UOG as they depreciate. Despite the requirement that the utilities forecast load and adjust their activities to mitigate impacts on bundled customers over time from their UOG, the Joint Utilities have only in the last few years made strides to improve their departing load forecasting.¹⁸⁰

The utilities have provided no reasonable basis or detail to support lifting the long-standing 10-year limitation on recovery of post-2002 fossil resources, and their proposal is unlawful. The Commission thus has no basis to modify cost recovery for existing post-2002 fossil UOG going forward.

2. Inclusion of Post-2002 Utility Owned Generation Costs in the CCA PCIA is Limited by Statute

The Legislature has provided for only limited recovery of post-2002 UOG costs from CCA departing load. AB 117 permitted recovery solely of the costs of "electricity purchase

¹⁸⁰ Exh. CalCCA-1 at 3-12.

contracts,” not UOG.¹⁸¹ AB 380 expanded the scope to include the costs of certain reliability resources procured through centralized procurement, which occurs through the CAM.¹⁸² Finally, SB 350 provided for the recovery of certain “incremental” resources required for renewable integration¹⁸³ and prohibited cost shifting in “additional procurement” under the IRP.¹⁸⁴

Indeed, there is no legal basis for continuing to include post-2002 UOG costs in the PCIA, particularly for CCA departing load. While the Public Utilities Code gives the Commission broad discretion under §701, that authority does not permit the Commission to move into the scope of CCA customer cost responsibility categories of costs that go beyond those specified in AB 117 without more express statutory authority to do so.

In fact, the Supreme Court of California has already spoken on the issue of the reach of §701. The Commission’s power under that section, according to the Supreme Court “does not authorize disregard by the commission of express legislative directions to it, or restrictions upon its power found in other provisions of the act or elsewhere in general law.”¹⁸⁵ Thus, the question becomes whether a specific statute conflicts, or may be harmonized, with § 701. In making this determination the Supreme Court has again turned to the maxim *expressio unius est exclusio alterius*.¹⁸⁶ For example, the Court found that the Legislature’s “express decision” to institute a permissive program cannot reasonably be interpreted to include the authority under § 701 and § 702 to impose a mandatory program.¹⁸⁷ The same logic applies here. Should the Commission

¹⁸¹ Cal. Pub. Util. Code §366.2(f)(2).

¹⁸² *Id.* §380(b)(2), (h).

¹⁸³ *Id.* §366.3.

¹⁸⁴ *Id.* §454.52(c) (emphasis supplied).

¹⁸⁵ *Pacific Tel. & Tel. Co. v. Public Util. Com.* (1965) 62 Cal.2d 634, 653.

¹⁸⁶ *Southern California Gas Co. v. Public Util. Com.* (1979) 24 Cal.3d 653.

¹⁸⁷ *Id.* at 736.

extend cost recovery of post-2002 UOG resources beyond the existing 10-year limit, CalCCA reserves the right to contest the legal basis on appeal.

VI. LONG-TERM RESOURCES SHOULD BE VALUED USING LONG-TERM VALUATION MEASURES (Common Outline §V)

Underlying most disputed issues in this proceeding is the question of portfolio valuation. AB 117 defines the scope of CCA stranded cost responsibility as the “estimated net unavoidable costs attributable to” departing load customers,¹⁸⁸ and requires those costs to be “reduced by value of any benefits that remain with bundled service customers...”¹⁸⁹ The Joint Utilities and TURN contend that 100 percent of the long-term resources in the portfolio should be valued using short-term sales prices the utilities “realize” for their limited excess supply. This is akin to saying that a family who purchased a house to obtain the security of a stable, long-term residence places a value on the house equal to the value they can realize for renting out a room in the house on AirBnB. In contrast, CalCCA contends that the Joint Utilities underestimate the value of the bundled portfolio by failing to recognize valuable attributes and ignoring long-term portfolio characteristics and value. To determine the extent of procurement costs to be allocated through the PCIA requires the Commission to make express decisions on the proper method of valuing the Joint Utilities’ portfolios.

A. The Commission Has a Depth of Experience in Portfolio Valuation

The Commission undertakes some sort of valuation in nearly every key proceeding. In ratemaking, it determines the marginal cost of various utility functions, such as generation capacity (MGCC)¹⁹⁰ and energy (MEC).¹⁹¹ The Commission also values a variety of products

¹⁸⁸ Cal. Pub. Util. Code §366.2(f)(2).

¹⁸⁹ *Id.* §366.2(g).

¹⁹⁰ Exh. SCE-04, phase 2 of 2018 General Rate Case Rate Design Materials at 96.

¹⁹¹ Exh. PCG-E-9, 2017 General Rate Case Phase 11 at 1-2.

and attributes in assessing the value of Energy Efficiency (EE), Demand Response (DR) and Distributed Energy Resources (DER) through the Avoided Cost Calculator (ACC). Using the ACC, the Commission estimates the value of capacity, ancillary services, energy, avoided RPS procurement and avoided GHG.¹⁹² As discussed further below, the Commission also has experience in long-term valuation in its development and maintenance of the Market Price Referent used in the RPS context.¹⁹³ Likewise, the Commission has calculated avoided capacity and energy costs under the Public Utility Regulatory Policies Act of 1978 for purposes of pricing the sale of power from Qualifying Facilities to the utilities.¹⁹⁴ Table 2A-3 provides a snapshot of the types of valuation the Commission and the Energy Commission have conducted in the recent past.¹⁹⁵ In short, the Commission is no stranger to the need to value products and attributes and the techniques to perform the valuation.

The Commission has performed valuation in the context of departing load costs in the past. It valued uneconomic portfolio costs in implementing AB 1890; the costs were measured partly by the proceeds of divested plants and partly using a market price benchmark.¹⁹⁶ The Commission initially valued the utilities' portfolios through the "DA In/DA Out" method.¹⁹⁷ In modifying the PCIA methodology in 2006, the Commission chose to value the portfolio for purposes of determining uneconomic costs using the MPB; it has since modified its valuation methodology, adding the Green Adder in 2011.¹⁹⁸

¹⁹² Avoided Cost Calculator User Manual, August 2016, <http://www.cpuc.ca.gov/General.aspx?id=5267>.

¹⁹³ See *infra* Section VI.C.

¹⁹⁴ See, e.g., D.10-12-035.

¹⁹⁵ Exh. CalCCA-1, Table 2A-3.

¹⁹⁶ AB 1890, *supra*, at §367.

¹⁹⁷ See D.06-07-030 at 5.

¹⁹⁸ D.11-12-018 at 17.

The Commission is asked in this proceeding again to consider methodologies to value the products and attributes in the Joint Utilities’ portfolios. CalCCA proposes a valuation methodology that considers most if not all products and attributes in the portfolio and recognizes the long-term nature of the utilities’ resource commitments. This proposal complies with statutory directives and guidance, while acknowledging current market limitations that prevent actual market transactions from accurately representing actual portfolio value and improves upon mechanisms and methodologies the Commission has successfully implemented in the past.

B. Portfolio Valuation to Determine Uneconomic Costs Must Recognize All Valuable Products and Attributes

The first step of portfolio valuation is to “identify products in the portfolio with value, whether explicit in the market or implicit in planning.”¹⁹⁹ Initially, the Current Methodology recognized only two products of value in the portfolio: System RA as a measure of capacity value and the *Platt’s* energy forward index as a measure of “brown” energy value.²⁰⁰ In 2011, the Commission acknowledged that the portfolio had additional value in the form of an RPS premium above brown power, which it represents in the Current Methodology as the Green Adder.²⁰¹

CalCCA submits that there are additional products and attributes in the portfolio that are not valued by the Current Methodology, which the Commission has explicitly recognized and relied upon in the Avoided Cost Calculator. In its direct testimony, CalCCA compared the attributes valued by the Current Methodology with “the range of products and attributes either traded in the market or identified by the Commission of having unique value....”²⁰² While there

¹⁹⁹ Ex. CalCCA-1 at 2B-3:5-8.

²⁰⁰ *See generally* D.06-07-030.

²⁰¹ D.11-12-018 at 17.

²⁰² Exh. CalCCA-1:4-5 and Table 2A-1 at 2A-3.

are several attributes not valued in the Current Methodology, CalCCA has focused on three attributes of additional value. As discussed in Section VII.A.3, increasingly value is being attributed to GHG-free energy above the value of brown energy. In addition, Section VII.A.1 explains that the Current Methodology recognizes only a generic capacity value, without regard for Local or Flexible RA attributes. Finally, as even the Joint Utilities acknowledge, the Current Methodology does not address ancillary services value.²⁰³ If these values are not considered in the measures used to value the portfolio, portfolio value will be understated, overstating uneconomic costs and understating the benefits retained by bundled customers.

Evasion of simple questions during cross examination regarding portfolio attributes suggests the Joint Utilities' awareness of this issue. Mr. Wan appeared less than clear that the three attributes in the Current Methodology fully reflect the scope of attributes and products embedded today in the utilities' portfolios. He identified four current portfolio products or attributes: capacity, energy, ancillary services and RECs.²⁰⁴ When asked whether he believed that these are the "only attributes of value in the overall portfolio," he replied "I'm not sure I said that."²⁰⁵ He then went on to say that "[t]hat was sort of the best four, and it could be today that those are the only four. But I doubt – I highly doubt that it will remain static."²⁰⁶ He further stated that he could not think at this point in time of any other attributes, but suggested perhaps the Mr. Cushnie could "answer that further."²⁰⁷ He likewise avoided a straightforward question about GHG-free attributes, whether as a portfolio manager he equates greenhouse gas-free

²⁰³ 1 Tr. 56:17-24.

²⁰⁴ 1 Tr. 56:17-24.

²⁰⁵ *Id.* 56:12-17.

²⁰⁶ *Id.* 56:27-57:2.

²⁰⁷ *Id.* 57:10-13

energy and brown energy.²⁰⁸ As the Joint Utilities’ main policy witness, Mr. Wan’s avoidance of these questions suggest his awareness that not all portfolio value is being captured in the Current Methodology; direct acknowledgement of such a fact would cut sharply against the Joint Utilities’ position and overall proposal.

The Commission reassessed the Current Methodology in 2011 to recognize additional portfolio value in the form of the Green Adder. CalCCA asks the Commission to once again examine the utilities’ portfolios to identify all products and attributes of value. Failure to capture all portfolio value in the PCIA calculation results in a cost shift from bundled to departing load customers.

C. Value Measures Used to Determine Uneconomic Costs Must Reflect the Long-Term Characteristics and Value of the Utility Portfolio

The Joint Utilities’ PCIA-eligible portfolios are dominated by long-term investments and long-term contracts. Of the estimated \$19.0 billion for PG&E, \$11.5 billion (61%) represents long-term RPS commitments, \$5.5 billion (29%) represents UOG investments and \$2.0 billion (10%) represents other long-term contracts.²⁰⁹ Of the estimated \$9.5 billion for SCE, \$8.5 billion (90%) represents long-term RPS commitments and the remaining \$1 billion (10%) represents UOG investments.²¹⁰ CalCCA submits that long-term resource values must be used to capture the full value of these resources – a proposition supported by Legislative mandate and Commission decisions.

As CalCCA’s witnesses explained, “[t]he value of products in the portfolio could be assessed by offering the products into the market under the same terms and conditions held by

²⁰⁸ *Id.* 57:20-24.

²⁰⁹ CalCCA-6, Corrected Figure 3-3.

²¹⁰ *Id.*

the portfolio (i.e., offering a 20-year contract for 20 years).”²¹¹ Alternatively, they observed “the value could be assessed by looking to the value of products sold” under similar terms and conditions.²¹² Until early 2018, however, the Joint Utilities had made no effort to engage in forward, long-term sales of contracts or products,²¹³ leaving only their RPS procurement to value the Green Adder and no long-term price to value capacity. In the absence of robust market prices for the sale of the same products with similar terms and conditions, “an administratively determined value used to guide utility procurement” must be used.²¹⁴

The Market Price Referent (MPR), a valuation tool used by the Commission in the RPS program, relies on long-term values. The MPR was implemented by the Commission as a result of SB 1078, which first enacted the RPS program.²¹⁵ The Legislature required the Commission to “establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators....”²¹⁶ The MPR has been used for different purposes, including allocating and awarding supplemental energy payments,²¹⁷ limiting a utility’s obligation to enter into contracts that exceed the MPR²¹⁸ and to implement “the Legislature’s mandate that the Commission determine the market price of electricity in order to evaluate the reasonableness of prices of long-term power purchase agreement (PPAs) for RPS-eligible electric generation.”²¹⁹ Importantly, the Legislature mandated the development of a referent that relied on the “*long-term* market price of electricity for fixed price contracts,” the

²¹¹ Exh. CalCCA-1 at 2B-3:14-17.

²¹² *Id.* at 2B-3:17-18.

²¹³ Exh. CalCCA-3 at 3-1 to 3-5.

²¹⁴ *Id.* at 2B-3:21 to 2B-4:2.

²¹⁵ *See* Ex. CalCCA-110, Senate Bill 1078 (Sher, 2002) Renewable Portfolio Standard Program.

²¹⁶ *Id.* §399.15(c).

²¹⁷ *Id.* §399.13(c).

²¹⁸ *Id.* §399.15(a)(1).

²¹⁹ *See, e.g.,* D.08-10-026 at 2.

“long-term ownership, operating, and fixed price fuel costs associated with fixed price electricity from new generating facilities,” and the “value of different products.”²²⁰

While the MPR has not been updated since 2011 and its use is limited, the Commission continues to rely on it as “the best method for comparing and determining cost savings for the RPS program....”²²¹ Moreover, the Commission has expressly rejected the utilities’ proposals to use short-term prices to determine the value of the RPS portfolio.²²² The Commission explained its concern with the utilities’ approach:

First, few, if any resources, in any of the large IOUs’ portfolios would be considered cost-effective, including low-cost hydroelectric and nuclear resources. Second, the large IOUs’ calculations are based on short-run avoided costs, and it seems unlikely the large IOUs would be able to procure 20% or more of their portfolios accounted for the RPS program under short-term contracts.²²³

CalCCA witnesses echoed this conclusion, noting that use of a short-term value for all volumes of a product in the portfolio creates distortions, stating:

This approach implicitly assumes that the utility could replace all of those long-term volumes in the current market at the then-current short-term price. Alternatively, it assumes the utility could replace all of those long-term products with short-term products and still satisfy the Commission’s expectation that the utility will provide customers a secure, reliable supply.²²⁴

For the same reasons, use of short-run avoided costs – even the price used in the Current Methodology – is an inappropriate value measure for 100 percent of the resources in the utilities’ portfolios.

²²⁰ SB 1078, *supra*, §399.15(c) (emphasis supplied).

²²¹ Exh. CalCCA-107, The Padilla Report – Costs and Cost Savings for the RPS Program (May 1, 2018), at 12.

²²² Exh. CalCCA-106, The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (May 1, 2017), at 12.

²²³ *Id.*

²²⁴ Exh. CalCCA-1 at 2B-4:15-2B-5:1.

Similarly, long-term value measures are at the center of valuation for energy efficiency, demand response and distributed energy resources.²²⁵ The Avoided Cost Calculator “is used to determine the benefits of resources across many Commission proceedings.”²²⁶ As CalCCA’s witnesses explained, “[t]he Calculator ‘produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours.’”²²⁷ In short, the Calculator reflects a valuation of a product, such as EE, based on its long-run avoided cost.

The testimony of Dr. Woychik, on behalf of UCAN, lends further credence to the need to rely on long-term measures to value long-term resources. He explained that “[t]here is always a price premium paid to reduce long-term uncertainty, which is a major part of the hedge value inherent in bilateral contracts; spot (physical) prices have little if any hedge values, so would systematically understate bilateral contract value.”²²⁸ He went on to explain that “[b]ilateral contracts usually represent plant characteristics, which can be used and applied in multiple markets, and accordingly represent option value.” He observes that “[s]everal parties, including UCAN, agree that the option value of bilateral contracts should be fully monetized and included.” Ms. Kehrein, on behalf of Energy Users Forum, reinforces these observations. She concludes that “to the extent that the current method undervalues utility assets, ignores the value of optionality (hedge value), does not price all components of contract value and results in lost value,” the Current Methodology cannot prevent cost shifts between bundled and departing load

²²⁵ Exh. CalCCA-1 at 2B-7:6-10.

²²⁶ D.17-08-022 at 3.

²²⁷ *Id.* (quoting Avoided Cost Calculator User Manual at 1).

²²⁸ Exh. UCAN-4 at 4.

customers.²²⁹ Indeed, even the Joint Utilities’ witness Mr. Wan acknowledges that optionality has value.²³⁰

The Joint Utilities also seem to agree that bilateral, long-term contract values can be used to value long-term RPS resources (although the parties disagree on the source of those values).²³¹ The Joint Utilities’ primary objections to using the current long-term contract measure to value its long-term RPS resources are not objections to using long-term contract values. Their objections lie in the reduction in the number of contracts that will be setting the benchmark over time,²³² the use of prices for newly delivering contracts, rather than contracts that are executed in that year,²³³ and the presence of prices from “mandated carve-out programs that are not indicative of fully-competitive RPS markets.”²³⁴ None of these concerns are rooted in the use of long-term values, but instead which long-term values should be utilized. Moreover, PG&E’s calculation of the cost shift it alleges is occurring under the Current Methodology relies on a group of non-utility long-term RPS contracts.²³⁵ The Joint Utilities indisputably recognize that valuing long-term resources using long-term value measures is reasonable.

Despite using long-term RPS values in their own calculations of cost shifts, the Joint Utilities argue against using long-term values in assessing the value of capacity – a view that is not only internally inconsistent but hard to square with the Commission’s use of long-term values in many other contexts. As discussed in Section VII.A.1, the 2018 capacity value of \$58.27 kW-year employed by the Current Methodology represents a short-run marginal capacity

²²⁹ Exh. EUF-1 at 4:5-8.

²³⁰ 1Tr. 60:6-22 (Wan).

²³¹ See *infra* Section VI.

²³² Exh. IOU-1 at 2-17:31-36.

²³³ *Id.* at 2-16:1-4.

²³⁴ *Id.* at 2-16:4-9.

²³⁵ See IOU-4A and IOU-1, Table 2-2 at 2-12.

cost. The Joint Utilities contend that even this short-term value is too high, suggesting that more reasonable assessments would include the average short-term sales price for excess RA supply.²³⁶ Using these short-term prices to assess cost shifts is in conflict with the Joint Utilities' view that "a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources."²³⁷

Finally, as CalCCA explained: "[u]sing long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction."²³⁸ Providing an example using RA capacity, CalCCA explains that this fiction "suggests an asset valued at \$110/kW-year in the planning process immediately loses value – dropping from \$110 to \$58 – the moment the asset becomes operational and its costs are included in the PCIA-eligible portfolio."²³⁹ This disconnect – between valuation used to determine if a resource should be procured and valuation used to determine the ongoing value of the resource once it becomes operational – is not rational. This approach "retains the option value of the assets for bundled customers but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation."²⁴⁰ In other words, departing load customers paying for benefits that are retained by bundled customers, contrary to the requirement of §366.2(g).

The evidence and Commission practices weigh heavily in support of the use of a long-term value measure to value long-term resources remaining in the utility's bundled portfolio. A sufficient range of values is available to recognize the long-term character of the utilities' portfolios, as discussed further in Section VII. In the long-run, CalCCA's SPA proposal, which

²³⁶ PG&E relies on the 2016 RA Report's average NP-26 average price of \$24.24 kW-year and, alternatively, a short-term price for excess supply sold by PG&E. *See* IOU-4, line 1 columns 2 and 3.

²³⁷ Exh. IOU-1 at 5-9:21-23.

²³⁸ Exh. CalCCA-1 at 2B-7:17-18.

²³⁹ *Id.* at 2B-7:18 to 2B-8:1.

²⁴⁰ Exh. CalCCA-1 at 2B-5:2-5.

contemplates a long-term sale of utility contracts and products in a more liquid market, should provide a reliable measure of market value for portfolio resources.

VII. CALCCA RECOMMENDS EMPLOYING A CORRECTED PCIA BENCHMARK METHODOLOGY TO DETERMINE THE PCIA UNTIL A MORE DURABLE, COMPREHENSIVE SOLUTION CAN BE IMPLEMENTED BASED ON VOLUNTARY, MARKET-BASED RESOURCE REDISTRIBUTION (Common Outline §VI)

The scope and magnitude of the problems presented by the Joint Utilities' uneconomic portfolios defy a quick and simple solution, and a long-term vision is critical. Over the next few years, all reasonable steps must be taken to reduce the costs of existing resources, employing tools such as contract buydown and UOG securitization proposed by CalCCA in Section X. Steps must also be taken to reduce the size of the utility portfolios and redistribute supply to new LSEs that need the supply to serve their customers. CalCCA proposes to voluntarily redistribute supply through a market-based mechanism, as proposed in subsection B, below, redistribution would commence in early 2020 and conclude in late 2021. Completing these steps will result in more reliable market value measures that can be used in the valuation of any portfolio resources retained in the Joint Utilities' portfolios. As the Commission and stakeholders move toward this end state, however, the Commission must continue to value the Joint Utilities' portfolios to enable the identification of uneconomic portfolio costs to be allocated through the PCIA.

The record suggests the only practicable solution in the near term to mitigate the risks of cost shifts between bundled and departing load customers is modification and improvement of the Current Methodology. The Joint Utilities' GAM/PMM proposal is not a viable short- or long-term solution; it is unlawful, devalues portfolio resources, threatens the viability of CCAs, and lacks sufficient detail to be ready for implementation in the near term, as discussed in Section VIII. Other proposals, such as TURN's Retail Seller Subscription and Commercial

Energy's VAAC, provide interesting ideas when considering a longer term solution, but lack sufficient detail and a comprehensive vision that can be immediately implemented. Modification of the Current Methodology provides a simple, turnkey solution that can be easily implemented for 2019 while developing the details of the SPA.

A. Correct the Current Methodology as a Bridge to a Longer Term Durable Solution

CalCCA proposes to correct the Current Methodology to better reflect portfolio value.

Specifically, CalCCA proposes as follows:

- ✓ *Capacity.* Adopt a capacity value that more reasonably represents the underlying value of the long-term resources and sufficiently addresses the range of capacity products provided by those resources; the proposed benchmarks value capacity needed to serve bundled customers using an administratively determined, long-term proxy adopted by the Commission for other purposes and value surplus capacity using a market-derived, short-term value.
- ✓ *GHG-free Energy.* Add a GHG-free resource premium, set at the amount of the Green Adder.
- ✓ *Ancillary Services.* Augment the benchmark to recognize the value of ancillary services capability associated with certain resources.
- ✓ *Green Adder.* Modify the Green Adder to remove the DOE variable that all parties agree is unworkable and augment the value to reflect prices for long-term contracts executed by the CCAs and a more limited extent, *Platt's* PCC-1 index.

1. Align Capacity Benchmark with Long-Term Capacity Value

The Current Methodology produces a capacity value for 2018 of \$58.27 kW-year,²⁴¹ which represents a short-run marginal cost value.²⁴² As CalCCAs witnesses explained, this value:

reflects only the annual unavoidable costs of having a combustion turbine available: fixed O&M, insurance and property taxes. It does not include any

²⁴¹ CalCCA-1 at 2B-6:11-12.

²⁴² See, e.g., 5 Tr. 1096:7-8.

long-term costs associated with capacity, such as the cost of constructing the CT.”²⁴³

Fundamentally, the product valued by this short-term measure is not the same product as the long-term capacity embedded in the portfolio.²⁴⁴ In addition to failing to capture long-term value, the capacity value does not distinguish between different types of capacity products – System, Local and Flexible RA.²⁴⁵

The Joint Utilities correctly identify the root of the challenge in valuing capacity in the utility portfolio. Referring particularly to UOG, they assert that “a market does not exist that would provide additional revenues to compensate for the full capacity value....”²⁴⁶ While parties agree on at least part of the problem the Commission faces, they disagree on the steps that should be taken to address it. The Joint Utilities propose to entirely avoid market valuation by instead allocating the bulk of RA through the GAM; combined with the CAM, approximately 64%-67 percent²⁴⁷ of all RA held in their portfolios will be allocated, not market-valued. In contrast, CalCCA proposes to rely on the interim on Commission-approved long-term capacity values to measure portfolio value, while developing an auction mechanism as a long-term approach that will allow more reliable market-based capacity valuation.

a) The Current Methodology Fails to Account for the Long-Term Value of Capacity

CalCCA witnesses concluded, consistent with the conclusions advanced in Section [X], that there is “[a]n egregious conflict” when short-term prices are used to value “attributes

²⁴³ *Id.* at 2B-6:16-18.

²⁴⁴ *See, e.g.*, 5 Tr. 880:9-15; *see also id.* at 886:24-26.

²⁴⁵ Exh. CalCCA-1 at 2B-6:18-22;

²⁴⁶ Exh. IOU-1 at 5-9:21-23.

²⁴⁷ Combining the Annual NQC MW values for CAM resources shown in CalCCA Confidential Rebuttal Exhibit 2B-1 with the Contract Capacity MW values for GAM and PMM resources in JU Direct Testimony Appendices F1, F2 and F3, the result is 64% for PG&E and 67% for SCE.

attached to resources acquired to meet long-term needs.”²⁴⁸ They further explained the problem in the context of capacity value:

Determining the value of long-term capacity held in the form of utility owned generation using the price obtained in the market for a one-year right to the capacity (or a series of one-year rights to capacity granted one year at a time) undervalues the asset by failing to recognize value in the long-term right. This disconnect is evident in comparing the Commission-approved long-term planning value for capacity of \$102.31/kW-year for Southern California or \$110.93/kW-year for Northern California to the current PCIA benchmark value of \$58.27/kW-year or to the prices paid by the CAISO using the Capacity Procurement Mechanism of \$75.72/kW-year.²⁴⁹

Moreover, as noted above, this disconnect creates the “untenable fiction” that resources procured at \$102.31/kW-year, consistent with planning values, immediately devalue to \$58.27/kW-year when the resource becomes a part of the PCIA-eligible portfolio.²⁵⁰ Long-term products – in this case capacity – must be valued using long-term value measures.

The Joint Utilities only exacerbate this disconnect, ignoring any long-term value of capacity by focusing solely on the short-term RA prices reported to the Commission in constructing their cost shift argument.²⁵¹ However, long-term costs for capacity are not recovered in those markets. Construction and ongoing capital costs are recovered via a number of other means: bilateral contracts; CAM cost recovery; traditional rate recovery; RMR contracts; CPM contracts and asset sales. The Joint Utilities ignore the potential to make use of these cost recovery tools for their long-term embedded costs, greatly underestimating the revenues they could receive if they were to sell their capacity in anything but the spot RA market.

²⁴⁸ Exh. CalCCA-1 at 2B-4:3-6.

²⁴⁹ *Id.* at 2B-4:6-14.

²⁵⁰ *Id.* at 2B-7:17 to 2B-8:1.

²⁵¹ Exh. IOU-3A, AppE-1:74 and AppE-2:74.

Long-term capacity has value that differs from the value of RA sold in the market for a month or even a year.²⁵² Long-term capacity resources provide “optionality” value. As CalCCA witness Hoekstra explained:

[A]s a general matter, the resources and assets in the PCIA-eligible portfolios are long-lived assets with significant ability to respond to conditions in the market in terms of their output. And ownership and control of assets gives the beneficiary the ability to manage the operation of those resources. In a power purchase agreement, having the ability to terminate, extend, adjust price, things like that, creates optionality.²⁵³

He went on to observe that long-term contracts also provide a hedging value:

Hedging corresponds more to hedging risk exposure. So to the extent that someone buying power in the market is exposed to market prices, obtaining an offsetting hedge that reduces that exposure perhaps by creating long-term supply, entering into long-term transactions with price certainty, that would tend to offset and mitigate that risk. That would be a hedging value.²⁵⁴

Mr. Hoekstra further explained that a “purchaser of power may be willing to commit to a long-term fixed price over a defined term to gain certainty as to the price it will pay, budgetary certainty, cash flow certainty, things like that.”²⁵⁵ The value of the premium would be realized by “gaining that certainty.”²⁵⁶

Dr. McCann followed on this point with an example based on PG&E’s 2016 draft renewable energy procurement plan. Reading from the plan, he stated:

PG&E’s fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of, one, delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement, and two, managing the risk of being caught in a seller's market where PG&E's potentially high mark[et] basis, potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with general need to manage overall RPS portfolio volatility based on demand and generation uncertainty,

²⁵² See *supra*, Section VII.A.1; see also 5 Tr. 13-19 (Hoekstra).

²⁵³ 5 Tr. 899:20-900:1 (Hoekstra); see also 5 Tr. 1093:25-1094:22 (Woychik).

²⁵⁴ 5 Tr. 900: 8-16 (Hoekstra).

²⁵⁵ 5 Tr. 900:21-25 (Hoekstra).

²⁵⁶ 5 Tr. 900:27-901:2 (Hoekstra).

PG&E believes it is prudent and necessary to maintain an adequate bank [that's the RPS bank] through the most cost-effective means available.²⁵⁷

He observed that “this was the basis for maintaining high cost RPS contracts in its portfolio and not disposing of those contracts.”²⁵⁸ CalCCA witness Marrinan added that one of the benefits that come with holding long-term resources is information and control over the resource, which are not conveyed through short-term attribute allocation.²⁵⁹ Allocation of resource attributes not coupled with information and control regarding the volume, timing and dispatch of those resources does not constitute a hedge but rather introduces uncertainty and volatility into the portfolio of the recipient CCA or other LSE.²⁶⁰

Dr. Woychik, on behalf of UCAN, further discussed the optionality embedded in long-term resources. In response to ALJ Roscow’s questions on the “receipt” method of valuing resources, he reinforced the differences between short-term and long-term products.

Now, we're going to try to apply under the utilities proposal, a short-run [marginal] cost to a long-run product, which had a lot optionality, and then you're going to say it's only value is just energy, very narrow, a very, very limited part of the optionality, in fact, a narrow slice of it, and say that's an appropriate value for the energy component. I think that's the mismatch....²⁶¹

He suggests “there’s long-run value to that in hedging and understanding you’re going to play that, but nobody’s discussing it except the CCA expert witness panel....”²⁶²

Additional capacity value for long-term resources is also demonstrated in UOG operations, which appear under the Current Methodology to be operated uneconomically.

CalCCA does not contend that these resources are uneconomic to operate; instead, CalCCA

²⁵⁷ 5 Tr. 901:10-902:1 (McCann) (quoting PG&E’s draft renewable energy procurement plan at page 19).

²⁵⁸ 5 Tr. 902:2-5 (McCann)(quoting PG&E’s draft renewable energy procurement plan at page 19).

²⁵⁹ 5 Tr. 904:28-905:2, 16-17 (Marrinan).

²⁶⁰ Exh. CalCCA-3 at 4-13:4-9, 5 Tr. 905:3-23 and 906:5-10, 15-26 (Marrinan).

²⁶¹ 5 Tr. 1096: 21-24 (Woychik).

²⁶² 5 Tr. 1097:1-8 (Woychik).

contends that the MPB understates the value of capacity for these resources, causing this distortion. CalCCA witness Kinoshian observed:

Based on the 2018 ERRA cost forecast and PCIA benchmark value, PG&E's fossil plants are not cost-effective to operate in 2018. Diablo Canyon operating costs are forecast to be \$878 million compared with a PCIA benchmark value of \$728 million (energy and capacity), for net uneconomic operating costs of \$150 million. Likewise, PG&E's fossil generation fleet is forecast to have a variable operating cost of \$334 million compared with a benchmark value of \$286 million, leaving \$48 million of uneconomic operating costs.²⁶³

Mr. Kinoshian concluded from these data that “either these facilities are not economic to operate, in which case they should not be operated, or the benchmark does not fully reflect their value.”²⁶⁴

Using Diablo Canyon as an example, he estimated that an \$85/kW-year capacity value must be assumed to justify the facility's operation.²⁶⁵ He similarly pointed out that “SCE's forecast of the fuel and direct GHG costs of dispatching Mountainview are more than \$20 million higher than the average MPB value of brown energy, and over \$12 million more than the on-peak PCIA brown energy value.”²⁶⁶ SCE's Palo Verde facility likewise shows operating costs that are “above SCE's proposed energy and RA” benchmark.²⁶⁷

Administratively determined capacity values recently approved by the Commission are readily available to capture the range of value in long-term capacity, as discussed more extensively in Section VII.A.1. CalCCA witness Hoekstra observed that the Commission's Avoided Cost Calculator provides such values. He stated: “[t]he Calculator values long-term capacity at \$102.31/kW-year for Southern California or \$110.93/kW-year for Northern California, compared with the \$58.27/kW-year adopted in PG&E's and SCE's 2018 ERRA for

²⁶³ Exh. CalCCA-3 at 2B-6:2-9 and Table 2B-1.

²⁶⁴ *Id.* at 2B-6:10-12.

²⁶⁵ Exh. CalCCA-3 at 2B-7:3-5.

²⁶⁶ Exh. CalCCA-3 at 2B-8:1-4.

²⁶⁷ Exh. CalCCA-3 at 2B-7:20-21.

PCIA calculation.”²⁶⁸ The values selected from the Calculator are for calendar year 2018, drawn from a model that provides annual values for calendar years 2016-2047.²⁶⁹

Finally, CalCCA’s witness Hoekstra pointed out that the Current Methodology’s capacity value even “understates actual short-term values reflected in the market.”²⁷⁰ In particular, the CAISO CPM has produced short-term RA prices of \$75.72/kW-year.²⁷¹ This value represents the value of purchases “to correct for the LSEs’ collective failure to procure sufficient RA for the 2018 year-ahead compliance filings.”²⁷² He explained further: “The price is not a planning value; it provides a transparent and variable price benchmark that accurately reflects actual transactions based on the near-term supply and demand balances for RA in both Northern and Southern California.”²⁷³

b) The Current Methodology Fails to Distinguish Among System, Local and Flexible RA Capacity

The Current Methodology’s short-term RA benchmark recognizes only one generic “flavor” of RA. In today’s market, however, there are three types of RA products, including System, Local and Flexible RA, and the market is ever-changing.²⁷⁴ The prices for these products may differ, even in the short run, as evidenced by the 2016 RA Report.²⁷⁵ Consequently, relying on a single, short-term generic RA value cannot adequately value the full range of RA products embedded in the Joint Utilities’ portfolios.

²⁶⁸ Exh. CalCCA-1 at 2B-7:14-16.

²⁶⁹ *See id.* at 2B-4, n. 2 and 2B-9, n. 7.

²⁷⁰ *Id.* at 2B-8:4-5.

²⁷¹ *Id.* at 2B-8:3-17.

²⁷² *Id.* at 2B-8:8-11.

²⁷³ *Id.* at 2B-8:11-14.

²⁷⁴ 3 Tr. 521:4-6 (Barkovich) (“We do have the three flavors of resource adequacy, which are system, local, and flexible.”); Ex. CalCCA-1 at 2B-6:18-22.

²⁷⁵ *See* Exh. CalCCA-108, Figure 6 at 26. Note, however, that timing of sales may affect price more than the type of RA. *See, e.g.,* CalCCA-103C, Fourth Quarter 2017.

Dr. Barkovich testified to the unique challenges of valuing Local RA. Using PG&E’s Humboldt plant as an example, she explained that this Local RA resource “is needed for local reliability and it isn’t cheap.”²⁷⁶ She observes that the CAISO has engaged in procurement over the last year to address shortfalls in Local RA procurement²⁷⁷ and concludes that using system RA to value the above-market portion of a local RA resource is “problematic.”²⁷⁸

Dr. Barkovich also suggested uncertainty about valuing Flexible RA. She noted that the product today is “not showing much of a premium above system RA in the market”²⁷⁹ although she points to growing conditions where this may change.²⁸⁰ Dr.

Woychik reinforced the message of change:

We certainly don't have all the flexible ramping capacity we need. That's another product. We don't have the flexible ramping product. The flexible ramping product is the tradable new product that Cal ISO's coming out with and there's three varieties of it, basically, in terms of time: 15 minute, five minute, and close to realtime.²⁸¹

Finding a reasonably representative value for short-term, let alone long-term, Flexible RA presents a challenge.

In an ideal world, long-term market values for all three flavors of RA would be available to reasonably value capacity in the Joint Utilities’ portfolios. Unfortunately, no long-term market values for capacity are available. Moreover, short-term values for each type of capacity, as Dr. Barkovich and Dr. Woychik testified, are difficult if not impossible to determine under changing conditions. For these reasons, CalCCA proposes “to avoid the complexities of valuing

²⁷⁶ 3 Tr. 525:18-22 (Barkovich).

²⁷⁷ 3 Tr. 521:20 – 522:3 (Barkovich).

²⁷⁸ 3 Tr. 525:10-12 (Barkovich).

²⁷⁹ 3 Tr. 526:4-17 (Barkovich).

²⁸⁰ 3 Tr. 526:4-6 (Barkovich).

²⁸¹ 5 Tr. 1095:2-13 (Woychik).

each product” and recommends the use of a single, long-term capacity value²⁸² as the most practicable and pragmatic solution.

c) The Current Methodology Should Be Revised to Reflect a Long-Term Value for Capacity Remaining in the Portfolio and a Short-term Value for Surplus Supply

Long-term capacity that provides value to bundled ratepayers, beyond simply meeting a one-year RA compliance obligation, should be valued using a long-term value measure, as explained in Section VI. While no market for long-term capacity exists to produce an explicit price referent, the Commission and the utilities “continue to use administratively determined long-term market values for making procurement and management decisions,”²⁸³ which could be used as proxies. In particular, the Commission has invested substantial time and resources to determine a long-term capacity value using its Avoided Cost Calculator.²⁸⁴ Although this value measure was developed for purposes evaluating the cost-effectiveness of procurement of EE, DER or DR, the Calculator is a valuation methodology that assesses the capacity value of these resources using an avoided cost methodology. CalCCA thus proposes to apply the Calculator capacity value for the year in which the portfolio is being valued to all capacity retained in the portfolio to serve bundled customers.²⁸⁵

Arguably, even surplus capacity held in the utility portfolio and sold in the market has long-term value if it serves as a hedge for bundled customers. For example, retaining surplus capacity in the portfolio mitigates the risk that the utility may have to buy RA at higher prices in the event of unexpected unit outages or generators being forced out, changes in regulations or

²⁸² Exh. CalCCA-1 at 2B-8:18-20.

²⁸³ *Id.* at 2B-7:4-6.

²⁸⁴ *See*, <http://www.cpuc.ca.gov/General.aspx?id=5267>.

²⁸⁵ Exh. CalCCA-1 at 2B-6.

other reasons.²⁸⁶ It also bears considering that such a buffer mitigates the cost recovery risk for shareholders by mitigating the risk of disallowance in the management of RA resources.²⁸⁷

2. Adopt a Benchmark to Reflect Ancillary Services Value

The Joint Utilities “hold capacity in their portfolios that provides or is capable of providing ancillary services to support their bundled load or to sell into the market.”²⁸⁸ The Current Methodology does not account for the value of ancillary services.²⁸⁹ The Joint Utilities appear to recognize this methodological oversight implicitly in providing for the allocation of Ancillary Services revenues under the PMM.²⁹⁰

The primary issue in controversy is the valuation of Ancillary Service capability. The Joint Utilities, consistent with their view that only “realized” revenues can be used to value products or attributes in their portfolios, would value the capability or services using the actual revenues received for Ancillary Services sales.²⁹¹ CalCCA, in contrast, proposes to use the Ancillary Services values derived in the Avoided Cost Calculator, currently \$2.81/kW-year in Northern California and \$3.46/kW-year in Southern California.²⁹² CalCCA recommends applying the value to “the resources held in the PCIA-eligible portfolio that provide ancillary services,” identifying those resources by the presence of Automatic Generation Control, which enables these resources to follow load.²⁹³ The effect of this modification is to increase the value

²⁸⁶ Exh. CalCCA-102-C at 3-4.

²⁸⁷ *Id.* at 2.

²⁸⁸ *Id.* at 2B-9:9-10.

²⁸⁹ *Id.* at 2B-9:10-11.

²⁹⁰ Exh. IOU-1 at 4-3:13-20.

²⁹¹ Exh. IOU-1 at 4-3:13-20.

²⁹² Exh. CalCCA-1 at 2B-9:14-16.

²⁹³ Exh. CalCCA-1 at 2B-9: 18-21.

recognized in PG&E's 2018 portfolio by an estimated \$10.1 million and \$10.4 million for SCE.²⁹⁴

3. Adopt a Benchmark to Reflect the Market-Recognized Premium for GHG-Free Energy

CalCCA proposes to augment the existing portfolio valuation measure to include an explicit premium above brown power prices for GHG-free resources.²⁹⁵ As CalCCA witness Kinoshian testified: "GHG-free generation carries a premium in today's market, although no reliable published market index values for this generation exist."²⁹⁶ The record supports this conclusion, calling for the addition of a GHG-free resource premium to GHG-free resources in the Joint Utilities' portfolios.

With the state (and many customers) highly focused on 2030 GHG reduction goals, the Joint Utilities are increasingly focusing their marketing and public relations strategies on GHG-free resources, regardless of whether the GHG-free resources are RPS-eligible. "Clean Energy Solutions" on PG&E's website advertises the GHG-free characteristics of various resources. It states: "Nearly 70% of the electricity we provide to our customers comes from sources that are greenhouse-gas free."²⁹⁷ Under "Fighting Climate Change," another tab on the website, PG&E emphasizes that "[a]s a provider of gas and electricity to millions of Californians, PG&E works hard to manage greenhouse gas emissions."²⁹⁸ Similarly, SCE's whitepaper, *The Clean Power and Electrification Pathway*, focuses on GHG reductions.²⁹⁹ Its "Preferred Pathway" identifies

²⁹⁴ Exh. CalCCA-1 at 2B-9:21 to 2B-10:2.

²⁹⁵ *Id.* at 2B-10 – 2B-11.

²⁹⁶ *Id.* at 2B-10:8-9.

²⁹⁷ Exh. CalCCA-116, "Clean Energy Solutions," page 1 of 6.

²⁹⁸ Exh. CalCCA-116, "Fighting Climate Change," page 1 of 6.

²⁹⁹ Exh. CalCCA-117.

as a goal “80% carbon-free electricity supported by energy storage”;³⁰⁰ focus on renewable resources specifically takes second stage.

One of the drivers for this value adder, Mr. Kinoshian notes, “is its marketing value when shown in the LSE’s Power Content Label.”³⁰¹ Public Utilities Code §398.4(a) requires: “[e]very retail supplier that makes an offering to sell electricity that is consumed in California shall disclose its electricity sources for the previous calendar year.” Under Energy Commission regulations, the utilities, CCAs and ESPs must separately identify the percentage of energy they deliver to customers attributable to generation from each type of renewable, coal, large hydroelectric, natural gas-fired, nuclear and other sources.³⁰² The PCLs are available to the public, enabling customers to judge potential service providers by the relative environmental friendliness of their portfolios. For 2016, PG&E’s portfolio included 69% GHG-free resources,³⁰³ thus enabling the “clean energy” marketing representations on its website. Power & Water Resources Pooling Authority, based on its PCL, appears to offer a low-carbon product, including 73% hydro energy and 27% from renewable resources.³⁰⁴

PG&E’s testimony in the Diablo Canyon Power Plant proceeding likewise validates a premium value for GHG-free resources. PG&E proudly stated in its testimony:

PG&E’s portfolio of electric resources has historically been one of the lowest emitting in the United States. At least one-half of the electricity supplied to PG&E’s bundled electric customers has consistently been GHG-free.³⁰⁵

³⁰⁰ Exh. CalCCA-117 at 4.

³⁰¹ Exh. CalCCA-1 at 2B-10:9-10.

³⁰² See Exh. CalCCA-118 (providing examples of Power Label Content disclosures for PG&E, SCE, and several other retail suppliers).

³⁰³ *Id.* PG&E 2016 Power Content Label.

³⁰⁴ *Id.* Power & Water Resources Pooling Authority 2016 Power Content Label.

³⁰⁵ Exh. IOU-118, Chapter 3 at 3-11.

It claimed that a “key element” of its proposal was that “it recognizes the value of GHG-free nuclear power as an important bridge over the next eight to nine years.”³⁰⁶ PG&E explained that in filling its Energy Efficiency “tranche” of GHG-free replacement resources, “[o]ffers will not be accepted unless they are below a RPS eligible resource cost cap” of \$82 kWh in 2016 dollars.³⁰⁷ As Mr. Kinosian explained, “PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to \$85/MWh in 2018 dollars.”³⁰⁸

Other evidence of GHG-free resource values can be found in the summary of “External Solicitations in Which PG&E Participated (2016-2018).”³⁰⁹ Of the 17 solicitations PG&E identifies, four sought proposals for energy products, with the remainder requesting proposals for RA products. Among those requesting proposals for the sale of energy, 100% requested proposals for “carbon-free” energy separate and apart from other forms of energy.³¹⁰

Finally, the Joint Utilities agree with CalCCA that there are no reliable published market index values” available for GHG-free resources. They also acknowledge, however, that other market participants have placed a value on GHG-free energy. The Joint Utilities how GHG-free transactions “are commonly traded among market participants across the Western Interconnection via voice brokers.”³¹¹ Explaining the formula used to calculation the “‘premium’ paid for GHG-free energy versus unspecified energy (*e.g.*, brown power), they

³⁰⁶ Exh. IOU-118, Chapter 3 at 3-1:35-36.

³⁰⁷ Exh. IOU-118, Chapter 4 at 4-5:20-21.

³⁰⁸ Exh. CalCCA-1 at 2B-11:3-5 (citing PG&E, Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms, Testimony, A.16-08-006, pp. 4-5).

³⁰⁹ Exh. IOU-3, Table 3-3 at 3-11.

³¹⁰ *See id.* Table 3-3 at 3-11, Rows 4, 6, 7 and 13.

³¹¹ Exh. IOU-3 at 2-25, n.73.

conclude that at a GHG allowance price of \$14.75/metric ton, “the potential value of GHG-free energy would be \$6.14/MWh,”³¹² They further observe:

Notably, on February 14, 2017, Sonoma Clean Power (SCP) estimated that its carbon-free “premium above the cost of general energy” was less than \$2/MWh. Additionally, the Short-Term Cost of Service Model included in the City of San Diego’s CCA Feasibility Study, published July 2017, estimated the cost of a carbon-free adder to be \$3.50/MWh.³¹³

It should also be noted that California provides a statutory premium for the Joint Utilities for GHG-free power, including that from large hydroelectric resources. Section 454.3 provides for a premium up to a full 1 percent on a utility's rate of return for investment in clean resources, mentioning in particular existing hydroelectric facilities.³¹⁴ This and other record evidence explained above make clear that there is no question whether there is a GHG-free premium embedded in the Joint Utilities’ portfolios, but the magnitude of that premium.

The Commission, in light of this evidence, cannot reasonably conclude that GHG-free energy carries no premium in the market. To do so would equate GHG-free energy with brown power – an equation that is anathema to California’s aggressive GHG reduction goals. Thus, the only questions are the appropriate premium to apply to GHG-resources and which GHG-resources should be valued using this premium.

CalCCA’s testimony proposed to apply the RPS premium – \$24.16/MWh for PG&E and \$25.11/MWh for SCE – to all of the IOUs’ GHG-free generation.³¹⁵ The impact of this change would be an increase in portfolio value of an estimated \$654.6 million for PG&E and \$218.5

³¹² *Id.*

³¹³ Exh. IOU-3 at 2-25:11-15.

³¹⁴ Section 454.3(a) provides for a return premium for investment in a facility “designed to generate electricity from a renewable resource, including, but not limited to, solar energy, geothermal steam, wind, and hydroelectric power at new or existing dams....”

³¹⁵ Exh. CalCCA-1 at 2B-11:13-19.

million for SCE.³¹⁶ Indeed, PG&E’s testimony in the Diablo Canyon proceeding and the Joint Utilities’ rhetoric surrounding GHG-free energy support this solution.

4. Correct the Green Adder by Removing the Outdated Department of Energy Benchmark Component

CalCCA proposes that the “Green Adder” be corrected by removing the unsupported and inaccurate Department of Energy referents in the calculation. The methodology and data source adopted in 2011 when the Green Adder was initiated is no longer effective or available. The source of the pricing information, which comes from programs identified in a database from NREL, is unclear.³¹⁷ In many cases the information is out-of-date, inaccurate or irrelevant.³¹⁸ The DOE information also systematically undervalues the retail green premium, in CalCCA’s calculations by at least \$10/MWh.³¹⁹ If the DOE referents were removed, the 2018 PCIA benchmark value would be increased by an estimated \$67 million for the PG&E portfolio and \$90.3 million for the SCE portfolio.³²⁰

Added to the PCIA benchmark in 2011,³²¹ the Green Adder was intended to add the market value of renewable resources into the MPB calculation.³²² In order to do so, the Commission stated its intent that the Green Adder should reflect “prices paid by buyers and sellers in recent transactions for delivery of RPS compliant power in California for the forecast

³¹⁶

Id.

³¹⁷

Exh. CalCCA-1, at 2B-12.

³¹⁸

Id. at 2B- 13; *see* Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised), A.17-06-005, August 28, 2017, at 11-13.

³¹⁹

Id. at 2B-14:13-14.

³²⁰

Id. at 2B-14:8-10.

³²¹

D.11-12-018. The Commission also revised the Capacity Adder, eliminated CAISO load-based costs in calculating the PCIA, replaced the use of a flat MPB weighting with a weighting based on the historical utility bundled load profile, and other DA-related changes.

³²²

Id. at 10

year.”³²³ The Commission chose to rely primarily on the utilities’ costs of procuring renewable resources, weighted at 68% of the benchmark, supplemented by “western regional renewable energy contract premiums published by U.S. DOE” for the remaining 32%.³²⁴ The DOE information is taken from survey of reported renewable energy contract premiums in the western United States compiled by the National Renewable Energy Laboratory.

However, the source of the pricing information, which comes from programs identified in a database from NREL, is unclear and of questionable utility. The NREL page on Voluntary Green Power Procurement does not provide any detailed information on individual programs. In communications with NREL staff, they stated data on individual programs has never been distributed.³²⁵ Moreover, some of the programs that have been relied upon in ERRA proceedings are now defunct and out of date.³²⁶ Data on the list indicates that it has not been updated since 2015 or perhaps even earlier. In all, CalCCA has identified at least 19 discrepancies out of the 89 programs listed, excluding consideration of other programs that may have been since added. Thus, there is simply no guarantee that the utilities are collecting data from all of the applicable programs across the western United States, or that the DOE website can constitute the third-party source the Commission no doubt intended.

Finally, the green power premium is calculated incorrectly. The premium is calculated against generation mixes that contain a varying mix of brown and green power, unlike the utility RPS Premium which measures 100% green versus approximately 100% brown power. The DOE Adder therefore undervalues the retail green premium.

³²³ *Id.* at 17.

³²⁴ *Id.* at 22.

³²⁵ Eric O’Shaughnessy, NREL, email communication, May 25, 2017.

³²⁶ Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised), A.17-06-005, August 28, 2017, pp. 11-13.

For these reasons, the current DOE/NREL portion of the green adder benchmark should be eliminated, and the benchmark should reflect only the average of utility RPS procurement costs. Procurement by three large utilities, each of them direct participants in a fully developed renewables market, should reflect a reasonable market value.

With this correction, the Green Adder used in the Currently Methodology should provide a reasonably representative value until the SPA can be fully integrated to provide an alternative value measure. Approximately “600 MW of new RPS resources will begin delivery to PG&E, 2,300 MW to SCE and 134 MW to SDG&E” over the next few years.³²⁷ If, instead, deliveries became too limited to produce a reliable value, the Green Adder could be blended on a limited basis (e.g., 25%) with the *Platt’s* PCC 1 index.

B. Adopt a Voluntary, Market-Based Solution That Will Reduce Utility Portfolio Size and Redistribute Resources, While Producing More Reliable Value Measures

Nearly all parties recognize that the Current Methodology is not a long-term durable solution for the problems of stranded costs, “double procurement” and an untenable mismatch between the Joint Utilities’ portfolio supply and demand. A more comprehensive solution must substantially slow utility procurement, reduce portfolio costs, maximize portfolio value and redistribute supply to avoid an untenable mismatch between utility supply and demand. In order to prevent cost shifts as required by statute, an effective solution must produce a valuation that recognizes the full benefit imputed by market forces for these long-term supply resources where resource control, resource information transparency, dispatch and all product attributes flow to the party paying the fixed and variable cost burden of the asset. CalCCA’s proposal is the only one submitted in this proceeding that achieves, let alone even attempts to achieve:

³²⁷ Exh. CalCCA-3 at 2B-10:14-16.

- Proposals to reduce portfolio costs through securitization and active portfolio management;
- The voluntary, long-term reallocation of portfolio resources to the LSEs that put the greatest value on control over those resources to serve customers; and
- The maximization of long-term resource value and a clear path to avoid wasting value inherent in the portfolio, such as the 10+ year RPS procurement attribute and the value of GHG-free energy.

CalCCA recognizes, however, that a durable solution will take time, requiring further analysis and planning by the Commission and stakeholders. In this context, CalCCA advances for further development a Staggered Portfolio Auction mechanism, which uses market forces to redistribute supply and provide more reliable valuation measures for the utilities' portfolios.

1. CalCCA's Proposed Staggered Portfolio Auction is a Voluntary, Market-Based Portfolio Allocation Mechanism to Redistribute Utility Supply

CalCCA's SPA allows all LSEs (IOUs, CCA, DA providers) to "voluntarily bid to procure resources, based on the value they and their customers place on these resources and their alternatives, to best serve their respective customer classes." Under the SPA, the market participant placing the highest value on the Joint Utility assets would prevail in the auction. This approach minimizes stranded costs and the need for PCIA recovery by maximizing the derived value of the assets.

CalCCA proposes that the utilities be required to offer 100% of the PCIA-eligible output of their RPS-eligible PPA, GHG-free resources, and energy storage resources (Auction Resources) in multiple tranches. These tranches would then be auctioned over time to other utilities, CCAs, ESPs, and other market participants. Auctions would be open to all market participants on a voluntary basis. For illustrative purposes CalCCA proposes that auctions be

held quarterly for two years, beginning in January 2020.³²⁸ This should allow time for Commission consideration and stakeholder input. CalCCA has provided projected volumes of the Auction Resources for the 12-year period from 2019-2030.³²⁹

Assuming a 2-year schedule, the auctions could be accomplished by holding eight separate auctions, each offering a diverse group of contracts to the market, with varying sizes, terms, locations and technologies offered. PPA resources would be auctioned by creating smaller marketable contracts out of the utilities' larger, long-term PPAs. These smaller volume contracts would generally mirror the original utility contracts with respect to term and type of products offered, but in smaller quantities. These smaller, and therefore less expensive, contracts would be attractive to a broad group of bidders. GHG-free UOG resources and RPS-eligible UOG resources such as small hydro and energy storage would be auctioned as blocks of energy and associated RA capacity. CalCCA has proposed tranches of 50 MW each, with a term and product attributes dependent on the energy in that particular tranche. For example, energy from certain resources may not be available after a certain date due to licensing constraints.

Although of course subject to the Commission's preference, under CalCCA's proposal the highest winning all-in bid in each tranche would set the market-clearing price for all of the products and attributes offered in that tranche. CalCCA proposes the Commission set a minimum bid price based on short term market prices, broker quotes or other metrics, and consider whether a limit should be placed on participant concentration, to allow for maximum liquidity of the market. It is assumed that the utilities would be active participants in the market given the requirement for them to sell 100% of their RPS-eligible Energy and GHG-free Energy

³²⁸ Exh. CalCCA-1 at 4-5:10.

³²⁹ Exh. CalCCA-3 at 4-2.

in the portfolios, and would bid aggressively to ensure receipt of some portion of these assets for their bundled customers. Because the utilities will be present as both the seller and potential buyer in many cases, CalCCA stresses the importance of Commission involvement in the design and implementation of any auction. Of course, the Commission could engage third-party consultants to aid it in developing auction mechanics, and in administering the auctions themselves.

2. The SPA Provides More Reliable Valuation Measures for the Utilities' Portfolios

The SPA not only maximizes the monetary value of the assets, but it significantly increases the value of those assets to the LSEs paying the fixed and variable costs associated with those assets. First, this approach provides the buyer with access to the full range of product attributes; the attributes proposed to be allocated and liquidated by the Joint Utilities represent only a subset of the attributes.³³⁰

Second, it provides the buyer with a product that can reasonably be considered a hedge to its load obligations. Product attributes that are allocated or liquidated in the short-term market by the utility, such as would occur under the GAM/PMM proposals, would leave all dispatch control of and information about these positions with the utility. The LSE receiving the allocation of attributes or the CAISO settlement of spot value does not have detailed information regarding hourly dispatch volumes or cost and lacks the requisite detail to rely on these allocations or settlements as even a short-term hedge to its load obligation and that does nothing to eliminate the need to procure long term resources. This proposed after the fact dump of

³³⁰ Exh. CalCCA-3, at 4-9.

attributes does nothing but introduce uncertainty and volatility to the recipient LSE's portfolio which represents a real and tangible cost shift to the subject LSE.³³¹

Third, the SPA provides control over the asset lives selected by the buyers so that they match the term of buyer load obligations and they meet the 10-year commitment requirement for 65% of RPS resources mandated by statute implemented by SB 350.³³² Short-term liquidations and allocations of attributes are not a reasonable hedge for a long-term load commitment nor do they provide for the LSE's requirement to contract for 10-year resources.³³³ Double procurement would continue under the Joint utility proposal.³³⁴

Fourth, the SPA provides control over the asset over the long term. The buyer can control the choice to retain or sell it in the future to match the ongoing needs of the buyer's portfolio.

Finally, the SPA, unlike the GAM/PMM, complies with §366.2(a)(5). CCAs retain procurement autonomy to determine the contents of the portfolio used to serve its customers.³³⁵ Consequently, CCAs are free to procure resources that meet the local needs and choices of the communities they serve.

3. The SPA Provides the Commission with the Ability to Structure the Details of the Auction Process to Ensure Efficiency and Optimal Outcomes

While CalCCA provides a "broad structural and conceptual framework"³³⁶ for an auction that would provide for the benefits outlined above, it also recognizes that auctioning these

³³¹ *Id.* at 4-13.

³³² Cal. Pub. Util. Code §399.13(b).

³³³ *Id.*

³³⁴ Exh. CalCCA-3, at 4-14.

³³⁵ Exh. CalCCA-3, at 4-8.

³³⁶ Exh. CalCCA-1, at 4-2:9.

resources represents a significant undertaking that should be taken on with the full review and approval of the Commission. Specifically, CalCCA recommended:

The Commission, after considering stakeholder input, will determine [the] auction structure and criteria and have final approval of agreements arising from the SPA. Details will be determined based on the Commission's preferences, which may involve implementation by an independent auction manager, review by an Independent Evaluator, PRG, and/or other stakeholder process.³³⁷

Further, CalCCA recognizes that adjustments to the process could improve outcomes and recommends that the auctions take place in stages to anticipate and allow for flexibility in the process. CalCCA initially suggests quarterly auctions during 2020 and 2021, with 12.5% of the portfolio included in each auction, offering "a diverse group of contracts to the market, with varying sizes, terms, locations, and technologies."³³⁸

There are several reasons for this recommended structure:

- **Increase participation and liquidity.** Multiple auctions would involve a narrower set of specific contracts and/or smaller volumes than a single comprehensive auction. This structure will likely be more attractive and/or more manageable for a greater number of bidders and thus would lead to greater participation and higher prices.
- **Flexibility to adjust for new events or information.** The quarterly auction approach allows for greater ability to adjust the specific contracts, quantities, and/or products being auctioned to account for new market developments, State policy changes, and/or reliability needs that affect LSEs' procurement practices.
- **Reduce risks of anomalous bidding behavior.** Multiple auctions over a period of two years would reduce the impacts of strategic bidding, gaming or other unforeseen behaviors by auction participants that would jeopardize the integrity of the auction process.
- **Mitigate effects of anomalous market conditions.** Multiple auctions spread out over time would average out price volatility, and therefore reduce the impacts of

³³⁷ Exh. CalCCA-1 at 4-5:7-12.

³³⁸ Exh. CalCCA-1 at 4-7:16.

unforeseen and temporary price increases or decreases compared to a single comprehensive auction happening once.³³⁹

4. The SPA Provides the “Sales Receipt” the Joint Utilities Claim to Need to Avoid Cost Shifts and is the Only Recommended Alternative Where the Receipt Matches the Product that the CCAs are Paying for Through the PCIA

CalCCA fundamentally disagrees with the assertion made by the Joint Utilities and TURN that the Commission must have a “sales receipt” for actual revenues from the sale of surplus power supplies to calculate the PCIA. The “sales receipts”, or short-term market prices, do not reflect the ranges of products and attributes in the portfolio, nor their long-term value. In other words, the sales receipts are for the wrong products.

It bears noting, however, that in stark contrast to the GAM/PMM short-term product proposal, the proposed SPA provide can provide a *relevant* “sales receipt.” Auctioning the portfolio resources on a long-term basis will produce receipts that reasonably represent the values the broader range of long-term attributes that are actually contained in the PCIA-Eligible portfolios. The SPA is the only proposal before the Commission that values the *relevant* products or seriously attempts to realize their full value.

5. A Residual Portfolio May Remain and Will Require Further Consideration

The Joint Utilities have accurately pointed out that there may be a Residual Portfolio of resources left if (1) not all auctioned resources are sold or (2) more than the utility forecast for departing load is realized. CalCCA proposes to address the Residual Portfolio by modifying the volumes offered in the eight quarterly auctions and/or 2) holding additional auctions beyond the initial eight quarterly auctions.

³³⁹ Exh. CalCCA-1 at 4-7:11 to 4-8:10.

During the initial 2 year quarterly auction period, CalCCA proposes that all resources sold be valued at the auction clearing price for purposes of calculating the PCIA. Resources that have not yet been sold will continue to be valued at the Corrected Benchmark price until sold.

To the extent that the Utilities' dual gloom and doom scenario of high departing load and high auction prices materializes, and further, the scenario unfolds whereby the utilities have underforecast departing load and are forced to buy back portfolio resources at a higher cost than book value, the overall impact to portfolio value would be overwhelmingly positive. The revenues from the auction would flow back to all PCIA responsible customers, offsetting the cost of the resources purchased in the auction. This balancing of PCIA cost responsibility and offsetting auction revenue benefit would carry to any Residual Portfolio auctions that may be needed.

6. The SPA Complements the Commission's Integrated Resource Planning Process and Support Environmental Policy Goals

The SPA provides the best option for the Commission to fully leverage the long-term supplies of RPS-eligible and GHG-free energy in the utilities' PCIA-Eligible portfolios to facilitate the IRP process and the achievement of California's environmental goals. The auctioning of RPS-Eligible and GHG-Free resources to the market participants that value them most would maximize the portfolio value by allowing bidders to buy long-term products and providing supply to the highest bidder. The direct conveyance of RPS-Eligible energy purchased under the utilities' existing PPAs supports compliance with the SB 350 requirement for 65% procurement through commitments of 10-years or longer. No other Party's proposal in this case even attempts to support these key imperatives.

CalCCA's modeling indicates that the RPS-Eligible and GHG-Free resources proposed for the SPA captures approximately 91% of the combined PG&E and SCE PCIA-Eligible

portfolios for the 12-year period from 2019-2030 with (whether measured by generation output, total costs or stranded costs.³⁴⁰ Thus, the scope of the proposed SPA is correctly defined to focus on the driving value from the most important and highest valued components of the portfolios. The implementation timeline and the forward procurement horizon of the SPA proposal is intended to align with the IRP process pending in R.16-02-007, allowing long-term LSE commitments to procure these resources beginning by 2020 and lasting at least 10 years forward to 2030 and beyond.

CalCCA's SPA proposal excludes fossil-fueled generation resources because there are good reasons to do so: a) fossil resources represent only about 5% of the generation output, costs and stranded costs in the utilities' PCIA-Eligible portfolios over the 2019-2030 period.³⁴¹ Consequently, fossil resources are not a major driver of value or stranded costs in the portfolio which lies predominantly in the RPS-Eligible and GHG-Free resources; and b) the majority of fossil resources are expected to drop out of the PCIA-eligible portfolios soon because of the 10-year cost recovery rule and/or because the relevant PPAs expire. However, fossil contributes about 14% of the RA Capacity in the combined PG&E and SCE 2019-2030 PCIA-Eligible portfolio but this contribution is concentrated in the next few years—it is projected to be nearly completely rolled off from the SCE portfolio by 2021 and from the PG&E portfolio by 2023.³⁴² CalCCA's proposal appropriately permits separate consideration of the reliability-related and RA Capacity-related issues associated with this contract roll-off in the Commission's IRP or RA proceedings where they are more appropriately addressed.

³⁴⁰ Exh. CalCCA-1 at 3-3:15-20.

³⁴¹ Obtained by adding the values for the "PPA-Other" and "UOG-Other" categories in the CalCCA Workpaper "Portfolio Reporting Template Final 040118.xlsx"

³⁴² *Id.*

7. The SPA Can Reasonably Be Implemented by January 1, 2020

The Joint Utilities acknowledge that CalCCA's SPA proposal has merit,³⁴³ and should be considered subject to sufficient development of the implementation details. CalCCA prudently recognized that the precise design of the proposed auction requires more evaluation and analysis than is possible within this phase of the proceeding, and therefore proposed a broad structural and conceptual framework for an auction process that can be further developed by the Commission in a subsequent phase of the proceeding.³⁴⁴ The timeline contemplated by CalCCA would have workshops on design of the SPA held from late-2018 through mid-2019, followed by with Commission review and approval of the SPA implementation details and an initial quarterly auction conducted by January 2020.

CalCCA's proposed approach provides ample time and opportunity for the Commission, guided by its own requirements and preferences and informed through the engagement of affected stakeholders, to develop a workable auction design that can be implemented in a reasonable manner.

C. CalCCA's Proposed Comprehensive Solution Aligns with the Guiding Principles for this Rulemaking.

The Scoping Memo clearly identified the overall goal of this proceeding and key principles to guide its resolution. CalCCA's proposed comprehensive solution, incorporating the Corrected Methodology and the Staggered Portfolio Auction, closely align with these goals.

Avoids cost shifts. CalCCA's proposal achieves the overall goal of this proceeding, and indeed the long-standing goal of the Commission in managing departing load impacts, of avoiding cost shifts. CalCCA concludes in Section IV that the Current Methodology shifts costs

³⁴³ Exh. IOU-3 at 1-3:1-5, 4-3:27-28.

³⁴⁴ Exh. CalCCA-1 at 4-2:6-10

from bundled to departing load customers by undervaluing the long-term utility portfolios and including costs that were not intended by the Legislature to be imposed on CCA customers. In the near term, CalCCA achieves this objective by correcting the Current Methodology. By correcting the value measure for capacity, adding values to reflect GHG-free and ancillary service values and correcting the Green Adder, CalCCA's proposal produces a reasonable portfolio valuation methodology. By removing Legacy UOG costs from PCIA-eligible costs, CalCCA's proposal aligns the PCIA calculation with the statutory directives regarding cost shifts. Over the next two years, CalCCA's proposal evolves to address cost shifting by enabling a more transparent and reliable allocation and valuation of portfolio resources through the Staggered Portfolio Auction.

Transparent, verifiable, confidential and predictable (Principles 1.a-b). Both the Corrected Methodology and the SPA provide transparent, verifiable, confidential and predictable means of calculating uneconomic cost responsibility. The Corrected Methodology achieves this objective by relying primarily on values calculated by the Commission for valuation, rather than actual transaction data. The SPA provides a transparent and verifiable result through an auction with publicly available price discovery; while the prices resulting from the SPA may vary more than administratively determined prices over time, the methodology produces a reliable result, predictable in the light of market conditions. Both approaches are made more predictable through the use of utility data, as framed in this proceeding, to enable long-term forecasting in the ERRA under the Modified Nondisclosure Agreement.

Flexible and accurate over time (Principle 1.c) The ability of any solution to address market conditions as competition increases is critical. CalCCA's proposal addresses this issue by transitioning over a two year period to a voluntary, market-based mechanism that allows all

LSEs, including the Joint Utilities, to modify their portfolios as they change and to reflect the impact of those changes in departing load charges.

Prevents unreasonable obstacles for non-utility LSE customers (Principle 1.d.) Unlike the Joint Utilities' proposed GAM/PMM, CalCCA's proposal does not erect new obstacles for customers of non-utility LSEs. These LSEs retain autonomy in developing portfolios to serve their customers that are consistent with their customers' needs. The proposal also prevents creating artificial burdens on non-utility customers as a result of failing to adequately value the utility's bundled portfolio.

Consistent with California energy policy goals and mandates (Principle 1.e.) Nothing in CalCCA's proposal reduces the obligations of any LSE to meet state energy policy goals. Moreover, CalCCA's proposal increases the capability of all LSEs to meet RPS goals as required by the Legislature in the way that best suits their customers' needs. A proposal that continues to shift costs to non-utility customers and prevents procurement autonomy, like the GAM/PMM, ties the hands of non-utility LSEs in making choices that will advance state interests.

Preserves procurement autonomy (Principle 1.f.) CalCCA's proposal allows non-utility LSEs to retain procurement autonomy by continuing to allocate uneconomic costs, rather than products or attributes. The Joint Utilities' forced product allocation under the GAM/PMM renders its proposal unable to fulfill this objective.

Provides payment flexibility (Principle 1.g.) CalCCA's proposal allows non-utility LSEs and their customers the ability to pay for their uneconomic cost responsibility through a PCIA charge and reduce the PCIA-eligible costs by procuring resources from the SPA. Moreover, CalCCA's proposal for prepayment enables non-utility LSEs and their customers to extinguish all or a part of their obligation in advance to add predictability to their planning.

Reflects legitimately unavoidable costs (Principle 1.h.) CalCCA’s proposal adheres closely to the statute permitting only “unavoidable” costs to be recovered through the PCIA. It achieves this goal by proposing cost reduction measures, including improved portfolio management practices, securitization of UOG assets and buydown and securitization of PPA prices.

Reflects value of benefits to bundled service customers (Principle 1.i.) CalCCA’s proposal is the only proposal that ensures that the cost responsibility of departing load customers is adjusted to reflect value remaining with bundled customers by ensuring reflection of long-term characteristics and value in portfolio valuation. In contrast, the Joint Utilities’ proposals make no adjustment to cost responsibility to reflect bundled customer value.

Preserves all resource value (Principle 1.j.) CalCCA’s proposal is the only proposal that ensures that all resource value is captured, through the use of portfolio valuation measures that recognize long-term value and the implementation of a SPA that effectively values all resource characteristics. In contrast, the Joint Utilities’ GAM/PMM sacrifices long-term value – particularly long-term RPS value, hedge value and optionality – through short-term allocation or sale of products and attributes.

Respects all existing agreements. (Principle 1.k.) CalCCA’s proposal does not contemplate any forced sale, assignment or termination of any PPA.

VIII. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES’ PROPOSED GAM/PMM. (Common Outline §VI)

A. The GAM Is Unlawful

The Public Utilities Code authorizes recovery of certain *costs* from CCA departing load customers. Public Utilities Code §366.2(f)(2) authorizes the recovery of “share of the electrical

corporation's estimated net unavoidable electricity purchase contract *costs* attributable to the customer.” Likewise, §454.51³⁴⁵ permits recovery of the *costs* of additional procurement under the IRP and the net *costs* of renewable energy integration resources procured by the utility.³⁴⁶ The law does not, however, give the Commission or the utility an unfettered right to allocate *resources* to CCA departing load, as the Joint Utilities propose to do under the GAM.

To the contrary, §366.2(a)(5) grants CCAs autonomy in procuring resources to serve its customers:

A community choice aggregator shall be *solely* responsible for all generation procurement activities on behalf of the community choice aggregator’s customers....³⁴⁷

The statute makes exceptions solely for “arrangements expressly authorized by statute.”³⁴⁸

The only statutory right for resource allocation to CCA departing load customers is very narrow. While §366.2(g) contemplates a reduction of cost responsibility *if* the “customers of the community choice aggregator are allocated a fair and equitable share of those benefits,” it does not *authorize* such an allocation. In only one instance – resource adequacy³⁴⁹ – does a statute contemplate the allocation of *resources* to a CCA, and then only after the Commission has taken the mandate for CCA procurement independence into account.

Section 380(g) provides for the utility’s recovery of the costs of “meeting or reducing resource adequacy requirements....from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made.”

Section 380(h) specifies the considerations the Commission must take into account in

³⁴⁵ *Id.* §454.52(c)(emphasis supplied).

³⁴⁶ *Id.* §454.51(c)(emphasis supplied).

³⁴⁷ *Id.* §366.2(a)(5).

³⁴⁸ *Id.*

³⁴⁹ *Id.* §380(h).

implementing subpart (g), including “[e]nsuring that community choice aggregators can determine the generation resources used to serve their customers.”³⁵⁰ (Notably, this provision was not yet enacted at the time the Commission adopted the CAM.³⁵¹) Taking the mandate for CCA procurement independence into account – and only then – may the Commission “consider a centralized resource adequacy mechanism among other options....”³⁵²

The GAM violates the statute’s express terms in allocating RECs to CCAs on behalf of their customers and fails adequately to consider the impact of further RA allocation on the procurement autonomy granted by statute to CCAs. As CalCCA witness Hoekstra explained, “[t]he GAM/PMM amounts to a move by the Joint Utilities to involuntarily force resources into CCA supply portfolios, leaving CCAs little space to compete on price or to choose their preferred sources of energy and capacity to serve their customers’ needs.”³⁵³

Allocation of RECs, rather than the “estimated net avoidable purchase contract costs,” would impair a CCA’s ability to be “solely responsible” for RPS procurement on behalf of its customers. CalCCA witness Hoekstra explained that a vintage 2017 CCA in SCE’s service territory “would, in 2020, receive an allocation of over 317,000 MWh of RPS-Eligible Energy, or **96%** of its 33% RPS compliance obligation for 2020” under the GAM, as depicted below.³⁵⁴

³⁵⁰ *Id.* §380(h)(5).

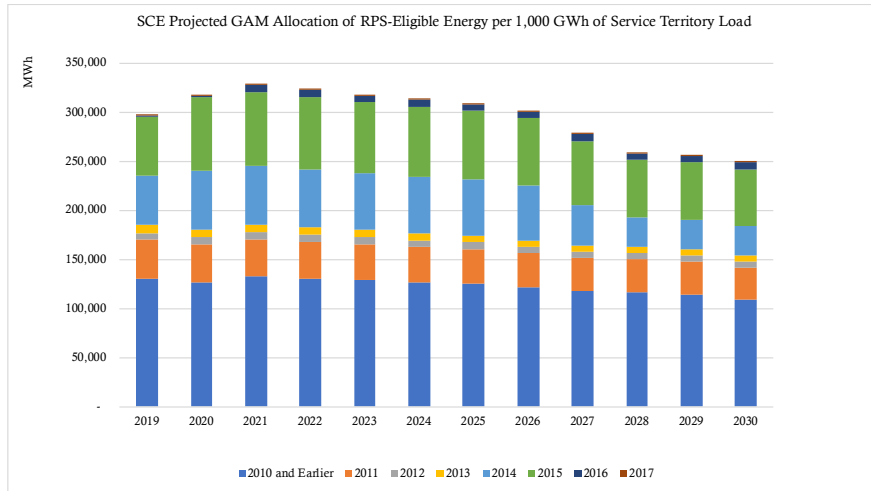
³⁵¹ *See* AB 380, *supra*.

³⁵² *Id.* §380(i).

³⁵³ Exh. CalCCA-3 at 4-8:1-2/

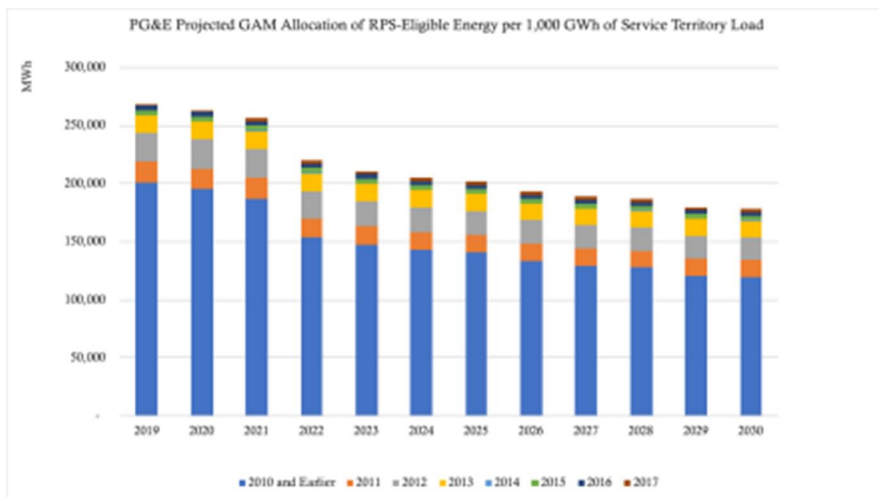
³⁵⁴ Exh. CalCCA-3 at 4-4 (emphasis supplied) and Figure 4-2 at 4-5.

Figure 4-2



Similarly, Mr. Hoekstra concluded that “[a] vintage 2017 CCA in PG&E’s service territory would, in 2020, receive an allocation of roughly 263,000 MWh of RPS-eligible energy, or 80% of its 33% RPS compliance obligation for 2020” under the GAM, as depicted below.³⁵⁵

Figure 4-1



³⁵⁵ *Id.* at 4-3 (emphasis supplied) and Figure 4-1 at 4-2.

Making matters worse, the RECs would be untradeable, as discussed in Section VIII.C once allocated to a CCA. Consequently, a CCA that is already fully or even partly RPS-resourced would be forced to sell off other resources in its portfolio to retain a supply-demand balance.³⁵⁶

While the Legislature provided a greater degree of flexibility in the context of Resource Adequacy, the statute does not support GAM RA allocation as proposed. The GAM's allocation of RA to CCA customers is unnecessary and would have a material impact on a CCA's sole procurement authority. Mr. Hoekstra examined the impacts of the GAM's RA allocation in both the SCE and PG&E service territories. For the SCE service territory, he concluded:

The illustrative vintage 2017 CCA in SCE's service territory would, in 2020, receive an allocation of roughly 48 MW of System RA Credit under the GAM; combined with the existing CAM allocation of 51 MW, the utility will have procured a total of 99 MW, or 44% of the CCA's 228 MW RA compliance requirements.³⁵⁷

He observed that “[a] CCA who is already 60% resourced could suddenly have excess or stranded capacity in its portfolio.”³⁵⁸ While to a lesser degree, a CCA in PG&E's service territory would still be saddled with 29% of its RA requirements under the GAM.³⁵⁹ Moreover, there is no evidence that the RA allocations provided by the GAM would be tradable once in a CCA's portfolio.

The GAM departs unambiguously from the Legislature's intent to provide CCAs sole autonomy in procuring resources to serve their customers. Moreover, there are clear options available to the Commission that would maintain that autonomy, protect against utility misuse if

³⁵⁶ See Exh. CalCCA-3 at 4-7:1-2 (“(A CCA who is already 60% resourced could suddenly have excess or stranded capacity in its portfolio.”).

³⁵⁷ Exh. CalCCA-3 at 4-6:2-5.

³⁵⁸ *Id.* at 4-7:1-2.

³⁵⁹ *Id.* at 4-5:1-5.

its market dominance, and the utility to continue to allocate stranded costs to CCA departing load customers. Under these circumstances, the Commission must reject the GAM/PMM.

B. The GAM/PMM Unreasonably Sustains Utility Market Dominance as Bundled Load Declines

The Joint Utilities have dominated the procurement arena since the beginning of utility history. The Legislature found in enacting SB 790, however, that “[t]he exercise of market power by electrical corporations is a deterrent to the consideration, development, and implementation of community choice aggregation programs.”³⁶⁰ It further concluded: “California has a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs.”³⁶¹

Today, PG&E serves roughly 60% of the load in its service territory, and 35% of the SCE service territory is in the midst of CCA formation.³⁶² The Joint Utilities’ control of the majority of resources in the service territory, as necessary to meet their anticipated load requirements, seems rational. Commission Staff and other parties agree, however, that the Joint Utilities will not be providing generation services to the majority of their native load by the mid-2020s.³⁶³ As their load continues to migrate to other alternatives, the utilities must reduce the size of their portfolios.

CalCCA’s proposed SPA contemplates this outcome and proposes to reduce the scope of utility resource control. The GAM/PMM, however, does not adjust the supply and demand balance in the market; it simply permits the utility to retain dominance and resource control

³⁶⁰ Senate Bill 790 (2011), Section 2(f).

³⁶¹ *Id.* Section 2(g).

³⁶² Exh. IOU-1 at 1-1:17-23.

³⁶³ *Id.*

while doling out limited, short-term allocations and CAISO settlements³⁶⁴ to CCAs each month or year. The GAM/PMM consequently risks continued “double procurement” and continued, unreasonable utility dominance in the wholesale market to the disadvantage of competitors.

The Joint Utilities echo the concern raised by the Commission’s staff that up to 85% of load could migrate away from the utilities’ portfolios by the mid-2020s.³⁶⁵ Joint Utilities’ witness Wan confirmed his belief that, for PG&E, 85% departure is a plausible scenario and, theoretically, even 100% departure is possible.³⁶⁶ Any departure more than 10% or 20% would, in his view, result in “excess supply.”³⁶⁷ Even today – without 85% departure – PG&E is “long” in RA, energy and RPS supply,³⁶⁸ and Mr. Wan expects that position to increase.³⁶⁹ Yet any plans for reducing the size of the portfolio, through divestiture of UOG or sale of RPS contracts, are at best unclear.³⁷⁰

Conditions under which the utility holds, for example, 85% of the resources necessary to supply its service territory but serves only 15% of the load would unreasonably sustain utility dominance to the disadvantage of CCA customers and the stability of the California electricity market.³⁷¹ As witness Marrinan explained:

This gross imbalance unnecessarily risks market manipulation and anti-competitive behavior that would harm all customers. Utilities would not only control the assignable assets, they would have superior knowledge of the expected resource volumes, planned resource maintenance, forced resource outages, and planned sales of allocable resources. This superior knowledge and asset control

³⁶⁴ See, e.g., Exh. IOU-1 at 1:18-28.

³⁶⁵ Exh. IOU-1 at 1-1:22-25.

³⁶⁶ 1 Tr. 36:2-13 (Wan).

³⁶⁷ 1 Tr. 36:25 to 37:21 (Wan).

³⁶⁸ *Id.* at 38:7-24 (Wan).

³⁶⁹ *Id.* at 38:26 to 39:1 (Wan).

³⁷⁰ See generally 1 Tr. 39-40:28 (Wan).

³⁷¹ See generally Exh. CalCCA-3, Chapter 4, §I.G. at 4-15.

would provide them with a highly unfair advantage to compete to supply generation to CCA or other departing load customers.³⁷²

She further explained that while utilities today are limited in their ability to impact spot prices, “because they have significant load that offsets their generation positions.... their net long generation position could create a market power issue.”³⁷³ Finally, she observed:

Given the potential harm an IOU could cause a CCA, the standard of care and oversight in this matter should be high. CCAs operate in an asymmetric market in which an IOU can cause CCA customers to experience higher generation (PCIA) costs. This means an IOU has a significant level of control over the cost risk that may drive CCA customers to opt out of CCA service. Such a situation should not be exacerbated as the GAM/PMM proposal would do.³⁷⁴

The GAM/PMM would place the Joint Utilities in a continuing position of dominance, controlling a material portion of the resources necessary to serve other LSEs and holding a substantial information advantage. For these reasons, the Commission should reject the GAM/PMM.

C. The GAM/PMM Devalues Portfolio Resources

1. GAM Allocations of RECs Reduce or Eliminate the “Bundled” and “Long-Term” Value of the Underlying RPS Resources

Long-term assets or contracts held in the portfolio are substantially different products than short-term rights to these resources sold in the market. Selective excess supply attributes sold on a short-term basis cannot convey the full value of the underlying resources and thus an incremental value is retained within the bundled portfolio – a value that by statute must be credited to departing load customers.³⁷⁵ Alternatively, however, selective excess attributes sold

³⁷² Exh. CalCCA-3 at 4-15:9-15.

³⁷³ Exh. CalCCA-3 at 4-15:23 to 4-16:4.

³⁷⁴ *Id.* at 4-16:4-10.

³⁷⁵ Cal. Pub. Util. Code § 366.2(g).

on a short-term basis may devalue the resource for all purposes, losing value for bundled customers without conveying the value to departing load customers.

The GAM's proposal for an allocation of RECs to departing load customers risks devaluing the underlying RPS resources. Contracts underlying the REC allocation have several uniquely valuable attributes, including their "bundled" and long-term characteristics. The GAM, however, cannot convey all of the value, but will convey the cost, of these attributes to departing load customers.

Bundled RECs have a value that is greater than unbundled RECs, due to the statutory requirement of §399.16(c)(2) that limits the use of unbundled RECs for compliance to 10% following December 31, 2016. As the Joint Utilities acknowledge: "the value of RECs varies significantly amongst the various portfolio content categories (i.e., PCC 1, PCC 2, PCC3)."³⁷⁶ By definition, however, transferring bundled RECs from the portfolio without the energy "unbundles" the RECs, potentially losing their PCC 1 value. To avoid this result, the Joint Utilities request a finding by the Commission that the RECs transferred under the GAM, "by virtue of that allocation, become 'unbundled RECs' as that term is used in Section 399.16(b)(3)...."³⁷⁷

The Joint Utilities' proposal runs directly contrary to the Commission's conclusions in D. 11-12-052. In delineating the categories of RPS complaint resources, the Commission explained:

Regardless of whether the original generation and RECs would have counted in the "bundled" category under D.10-03-021, or in another portfolio content category under new § 399.16 if the RECs had been retired for RPS compliance without being transferred, once they are unbundled and transferred, the RECs are

³⁷⁶ Exh. IOU-1 at 4-40:31 to 4-41:1.

³⁷⁷ Exh. IOU-1 at 4-44:12-15.

by definition unbundled RECs, subject to the rules of that portfolio content category.³⁷⁸

The Commission further observed the “overarching tenet that once RECs have been unbundled and sold separately from the RPS-eligible electricity with which they were originally associated, the electricity may not be used for RPS compliance.”³⁷⁹ While the Joint Utilities attempt to “nuance” this point, suggesting that these RECs are not being “sold,”³⁸⁰ the fact remains that the customer “is paying for the REC.”³⁸¹ If, instead, the Joint Utilities were to sell RPS contracts, the REC would retain its bundled status.³⁸²

Even assuming the Commission could “nuance” statutory compliance by deeming allocated RECs to be “bundled” RECs, the RECs would be devalued. The Joint Utilities contend:

It should be noted that LSEs are not required to use the allocation of attributes they receive on behalf of their customers, and can instead elect to sell them (or not use them, although it would be uneconomic to do so).³⁸³

On the stand, however, Mr. Cushnie acknowledged that he had not considered the potential loss of the bundled attribute if the LSE resold the REC to a third party. After consideration, he concluded: “If they are selling bundled REC, it remains an unbundled REC.”³⁸⁴ In short, while the RECs may be tradable, they lose value if that ability is exercised.

A similar problem arises with the “long term” attribute associated with RPS resources. Beginning in 2021, §388.13(b) requires that 65% or more of RPS compliance must come from contracts of a term of longer than 10 years or resource ownership, conveying greater value on

³⁷⁸ D.11-12-052 at 55.

³⁷⁹ *Id.* at 56.

³⁸⁰ 2 Tr. 293:1-5, 404:23-405:4 (Cushnie).

³⁸¹ *Id.* at 367:28 – 368:6-10 (Cushnie).

³⁸² 2 Tr. 295:26 – 296:1 (Cushnie).

³⁸³ Exh. IOU-1 at 4-41:4-7.

³⁸⁴ *Id.* at 292:6-8 (Cushnie).

these longer term arrangements. Under the GAM, however, the utility would have no contract commitment to transfer RECs to an LSE for any period, and would only transfer them after they are generated, on a quarterly basis.³⁸⁵ The LSEs receiving the RECs would not be party to the underlying contracts.³⁸⁶ Yet the Joint Utilities claim that allocation would be a “significant reduction in the required new long-term contracting by other load-serving entities.”³⁸⁷ In reality, the CCAs could not rely on the short-term allocations to meet their statutory requirement for 10-year resources even if it were not unlawful to count the allocations toward this requirement. The amount of time it would take a CCA to construct or procure 10-year resources in the event of a shortfall in anticipated allocation would significantly outstrip the notice period provided by the utility regarding the quantity of RECs to be allocated. The result of a CCA properly managing this risk would be a continued “double procurement” of resources. Again, the Joint Utilities attempt to distinguish the GAM on grounds that “we’re not selling it to a load-serving entity....”³⁸⁸

The Joint Utilities again ignore the language of the statute. Section 399.13(b) provides:

Beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the renewables portfolio standard requirement of each compliance period shall be from *its* contracts of 10 years or more in duration or in *its* ownership or ownership agreements for eligible renewable energy resources.³⁸⁹

The short-term GAM allocation does not somehow transform the unbundled REC, or even a bundled REC, into the *receiving LSE’s* long-term contract or ownership. Not even interpretation by the Commission can overcome the plain language of the statute. Moreover, as with the

³⁸⁵ Exh. IOU-1 at 4-23:14-21.

³⁸⁶ 2 Tr. 299:15-18 (Cushnie).

³⁸⁷ *Id.* at 300:3-9 (Cushnie).

³⁸⁸ *Id.* at 301:16-19 (Cushnie).

³⁸⁹ Cal. Pub. Util. Code §399.13(b)(emphasis supplied).

“bundled” characteristic, the Joint Utilities acknowledge that the receiving LSE cannot “sell that long-term attribute to other load-serving entities.”³⁹⁰

2. The GAM/PMM Fails to Preserve and Convey All Value of the Portfolio Resources

Long-term contracts and assets carry value beyond the value of short-term rights to products unbundled from those contracts or assets, including hedge value and optionality. The GAM allocation does not convey those values to departing load customers, leaving the value behind in the portfolio to support bundled portfolio management.

CalCCA witnesses Marrinan and Hoekstra identified the loss of value for departing load customers in several respects:

- “[T]he GAM fails to recognize, let alone capture and preserve, the wider range of values inherent in the RPS-eligible and Large Hydro resources included in the GAM, including GHG-free energy value, hedge value and other products.”³⁹¹
- “[T]he GAM fails to capture and convey the incremental value from the optionality associated with the resources, which could be significantly greater if allocated to LSEs rather than liquidated in the energy market...” including the “flexible storage, dispatch, ramping and arbitrage capabilities inherent in Large Hydro (including pumped storage” and the “flexibility in the administration of RPS resources (e.g., curtailment provisions, term extensions, price resets, etc.).”³⁹²
- The PMM “merely transfers costs to CCAs without any transfer of control over the resources themselves [which is] more fully realized and maximized when conveyed between counterparties via forward contracts and forward contract prices....”³⁹³
- The PMM fails to realize the “value of GHG-free energy available from nuclear resources or the intrinsic forward gas conversion tolling value of gas resources....”³⁹⁴

³⁹⁰ 2 Tr. 301:16-19 (Cushnie).

³⁹¹ Exh. CalCCA-3 at 4-9:1-17.

³⁹² *Id.* at 4-9:18 to 4-10:3.

³⁹³ *Id.* at 4-10:20 to 4-11:8.

³⁹⁴ *Id.* at 4-11:9-14.

- The PMM fails to realize “extrinsic” resource value, “stemming from the ability to adjust dispatch operations upward or downward in order to capture incremental value in response to short-term price volatility that, by definition, cannot be captured by liquidation of energy at the time of expiration of the option in the spot market.”³⁹⁵

Moreover, despite the utilities’ claims to the contrary, the GAM/PMM does not produce the value of predictability for departing load customers. As Ms. Marrinan explains: “The quantities will vary from quarter to quarter for RECs and month to month for RA...[t]he utilities remain owners of the assets and are free to dispose of them as they wish and at prices they consider reasonable with timing they manage to fit their needs.”³⁹⁶ This would leave CCAs unable to predict what will be available to them.

The result would be a significantly loss of value in the hands of departing load, leading to a “portfolio that is un-hedgeable, unmanageable and whose costs are highly volatile.”³⁹⁷ Hedge value in GAM is insufficiently transparent for practical planning purposes. To the extent that the GAM rate reflects the hedge value inherent to the underlying contract for the resource, the aggregated nature and ever-changing composition of the IOU portfolios makes it nearly impossible to use those hedges to practically manage a CCA’s positions. Ms. Marrinan anticipates that “CCAs would be forced to continue to engage in resource planning that would involve building assets or acquiring long-term assets through contracts that they control and that provide a hedge to their load obligations.”³⁹⁸

³⁹⁵ *Id.* at 4-11:15-21.

³⁹⁶ Exh. CalCCA-1 at 4-13:4-9.

³⁹⁷ *Id.* at 4-13:16-17.

³⁹⁸ *Id.* 4-14:18-20.

The GAM/PMM threaten significant loss of value as long-term utility resources are conveyed quarterly or annually, on a short-term basis. The proposal thus fails to meet the Guiding Principles advanced in the Scoping Memo.

D. The GAM/PMM Is Not a Long-Term Solution Yet is Too Incomplete and Complex to Serve as an Effective Interim Solution

The Joint Utilities have marketed the GAM/PMM solution as a simple “turnkey” solution reforming the uneconomic cost allocation methodology. The GAM/PMM presents anything but a simple solution. The only “turnkey” solution in the short-run is modification of the Current Methodology to reduce the risk of cost shifts between bundled and departing load customers.

The Commission lacks the requisite legal authority to implement the GAM, and the GAM/PMM will result in a loss of value of the underlying portfolio resources. In addition, the proposal suffers from numerous flaws that will prevent simple or timely implementation.

First, the Joint IOUs acknowledge that changes are required to the Power Content Label rules to ensure the proper accounting for resources subject to GAM/PMM.³⁹⁹ They further acknowledge that these issues are not within the scope of this Commission’s jurisdiction but instead lie within the Energy Commission’s discretion.⁴⁰⁰ Resolution of these complex, multi-jurisdictional issues is unlikely to be completed for a “turnkey” implementation of the GAM/PMM on January 1, 2019.

Second, the question of how banked RECs should be addressed in the GAM/PMM proposal has not been adequately explored. The Joint Utilities propose allocating banked RECs from the IOU portfolios to departing load ratably over the term of the longest contract in the

³⁹⁹ Exh. IOU-1 at 4-45.

⁴⁰⁰ 2 Tr. 302:17-21.

vintaged portfolio.⁴⁰¹ Setting aside the questionable equity of such a proposal (why do bundled customers have full access to their bank immediately, but departing load customers are slowly given their bank over 20-30 years?), the regulatory and legal basis for such a change is unclear and would need to be reviewed considering all the facts prior to implementation.

Third, multiple recalculations of GAM RA amounts make planning to meet RA requirements a moving target.⁴⁰² Under the Joint IOU proposal, GAM RA allocations would be initially determined in August based on year-ahead load share. The allocation would subsequently be updated during the month-ahead and mid-year periods, introducing significant uncertainty to the actual GAM RA allocations that the departing load entity would receive. As noted in Section VIII, this uncertainty complicates departing load resource planning and creates a barrier to hedging by CCAs.

Fourth, the Joint Utilities propose complex rules for replacement and substitution of RA on behalf of the LSEs receiving allocations.⁴⁰³ The Joint IOUs propose a complex, tiered process for RA replacement and substitution for the GAM RA portfolio that has implications for the CAM and PMM portfolios. For example if GAM RA requires substitution, the Joint Utilities propose leaving it to their discretion to choose from a menu of options including drawing from the PMM portfolio, the CAM portfolio, or even procuring new resources to meet the substitution requirement. Keeping track of numerous transactions and ensuring they were all done reasonably will be a challenging task for the utilities, Commission and stakeholders. Oversight to ensure fairness would be critical to such a process and further stakeholder input would be required to fully vet the overlapping issues introduced by this aspect of the Joint IOU proposal.

⁴⁰¹ Exh. IOU-1 at 4-22, n. 5.

⁴⁰² *Id.* at 4-25:19 to 4-26:22.

⁴⁰³ Exh. IOU-1 at 4-28:1 to 4:29:17.

Fifth, the Joint IOUs propose a stakeholder process including the IOUs, CCAs, ESPs and CAISO to determine how to avoid stranding import RA under the GAM proposal.⁴⁰⁴ Such a process would be necessary to implement the Joint IOU proposal and would need to be completed prior to implementation GAM/PMM to ensure resource value is not lost. Again, completion of this process is unlikely to occur in sufficient time for a 2019 implementation.

Sixth, while the Joint Utilities' criticize the longer term auction strategy proposed by CalCCA as "incomplete,"⁴⁰⁵ the PMM auction – which the utilities propose as a near-term solution – raises many issues that would need to be addressed prior to implementation. For example:

- ✓ The combination of departing load and bundled load transactions, with the utilities on both sides of the transaction in the same RFO, raises significant oversight issues that need to be carefully considered. Although the Joint IOU testimony reference rules used in CAM Energy Auctions, the PMM process is more complex and any such rules would need to be revisited.
- ✓ The PMM auctions could be subject to gaming. The Joint Utilities offer no discussion of what bid selection criteria would be used to award RA contracts. It is unclear how they propose to avoid a situation where RA in the Q1 long-term RA sales RFO is sold at artificially low prices instead of holding back such a quantity for sale later in the year. Departing load customers would have no influence over such decisions, but would bear the financial consequences of the utilities' decisions. Moreover, if the Joint IOUs award RA contracts at artificially low prices, this could lead to speculation and market manipulation that could impair the ability of all parties to meet their RA obligations.

The GAM/PMM thus not only fails on legal and policy grounds but fails to offer a solution that can be implemented in the near term. It also introduces a possible volatility and opportunity for market manipulation which the Commission has indicated is a high concern in the current dynamic marketplace. The only near-term solution is to modify the Current Methodology to

⁴⁰⁴ *Id.* at 4-29:18-33.

⁴⁰⁵ Exh. IOU-3 at 4-2:27-28.

mitigate the risk of cost shifts and look toward a more comprehensive reform over the next two years, as proposed by CalCCA.

IX. IMPROVEMENTS IN PORTFOLIO MANAGEMENT PRACTICES SHOULD BE ADOPTED TO REDUCE AND PREVENT FURTHER ACCUMULATION OF UNECONOMIC PORTFOLIO COSTS (Common Outline §VII)

A. The Commission Should Direct the Joint Utilities to Modify Their Forecasting Practices to Better Account for Departing Load

The Commission and the Joint Utilities have long been aware of the need to consider and forecast departing load in developing and implementing procurement. The issue was central to the procurement by the California Department of Water Resources (CDWR) following the energy crisis. In D.03-04-030, the Commission established an exemption from the CDWR Power Charge based on CDWR's forecast of departing load. It stated:

It is clear that DWR, when negotiating long-term power contracts, assumed that a certain amount of customer generation departing load would occur every year and therefore did not procure long-term power for that portion of the load. In fact, such an assumption is based on common sense, since utilities have always faced departing load in various forms, including that caused by an economic downturn, improvements in energy efficiency and building codes, as well as installation of self-generation systems.⁴⁰⁶

The Commission drew two important conclusions, relevant to this proceeding: forecasting departing load is “common sense,” and departing load accounted for in a forecast underlying a procurement plan should be exempt from cost responsibility for resources procured in implementing that plan.

Despite this clear awareness (or perhaps in response to this awareness), the Joint Utilities undertook the most extreme short-term focused and narrow approach to forecasting departing load from the outset of CCA formation. As evidenced in the cross examination of the Joint Utilities witnesses, the Joint Utilities refused to forecast CCA departing load in developing or

⁴⁰⁶ D.03-04-030 at 54.

implementing procurement plans absent near certainty that a particular load would depart.

Mr. Cushnie explained:

In the case of Southern California Edison, what we're looking for is for the newly-forming CCA to give us sufficient confidence as to their formation plans so that we can then plan to balance the portfolio around their formation intentions. To date, only one of our CCAs has provided a binding notice of intent, which is the Commission's regulatory process that tells us that we can now officially not plan to serve that load.⁴⁰⁷

As a result of this standard, SCE failed to forecast any CCA departing load until its 2016 ERRA filing, after Lancaster Choice Energy customers departed in mid-2015.⁴⁰⁸ Mr. Lawlor stated that PG&E forecasts departing load in a “similar fashion.”⁴⁰⁹ He further observed: “I truly think our forecasting is getting better, but you know, nothing better than a binding notice of intent.”⁴¹⁰

Another major forecast shortcoming was that the Joint Utilities focused on the very short-term and on the precise date that a particular CCA load would depart over the next year in the annual ERRA Forecast process and did not consider the long-term plausible range of potential departing load over the 20-30 year horizon covered by the long-term resource commitments they were making. Until just the past couple of years, the Joint Utilities generally assumed that future departing load would continue on a flat-line basis for an indefinite number of years into the future at exactly the same level as the most recent year-ahead ERRA forecast, without regard for potential future departing load several years into the future. Consequently, the Joint Utilities’ narrowly-defined departing load forecasting approach missed the forest for the trees, and completely missed the potential for the dramatic increases in departure that we are being experienced

⁴⁰⁷ 4 Tr. 809:20-810:3 (Cushnie).

⁴⁰⁸ 4 Tr. 825:1-3(Cushnie).

⁴⁰⁹ 4 Tr. 813:9-10 (Lawlor).

⁴¹⁰ 4 Tr. 814:13-16 (Lawlor).

now. Indeed, the record in this case is replete with references to the potential departure of up to 85% of the Joint Utilities’ bundle load within the next several years – but is devoid of even a hint that the utilities have any structured forecast or plan to deal with the consequences of that outcome.

Mr. Lawlor further confirmed PG&E’s historical forecasting practices. He confirmed that PG&E was aware of the intent of Marin Energy Authority (MEA, now Marin Clean Energy or MCE) to launch a CCA in 2010, as evidenced by implementation plans submitted to and certified by the Commission.⁴¹¹ Despite this knowledge, he explained, PG&E “concluded we needed to use more of a bright line methodology, and that looked at binding notice of intent or basically when they go live....”⁴¹² Consequently, PG&E did not forecast MEA’s departure before its launch.⁴¹³

PG&E’s failure to actively forecast CCA departing load had serious consequences for MEA and its customers. PG&E continued to procure resources now attributed to MEA’s customers’ behalf for another seven months *after* the load had already departed.⁴¹⁴ In fact, PG&E executed contracts for an additional 1.7 GW of new capacity now attributed to MEA’s 2010 departing load despite full knowledge of MEA’s intent to launch, with contracts totaling more than 600 MW executed after the load had already departed.⁴¹⁵

Adding insult to injury, the Joint Utilities’ witnesses acknowledged that advance knowledge of MEA’s departure *would not* have altered their procurement plans.

⁴¹¹ 4 Tr. 817:13 – 820:16; 821:26-822:3 (Lawlor).

⁴¹² 5 Tr. 857:13-17 (Lawlor).

⁴¹³ 5 Tr. 857:18-21 (Lawlor).

⁴¹⁴ See Exh. CalCCA-123, PG&E 2010 Contract Execution Dates From Attachment 10 ALJ Requested Data Matrix; see also 4 Tr. 820:17-823:20 (Lawlor).

⁴¹⁵ See Exh. CalCCA-123, Maximum Contract Capacity.

Mr. Lawlor stated that “Marin as a percentage of PG&E's total load was between 0.1 percent and 0.2 percent” in 2010.⁴¹⁶ In Mr. Lawlor’s opinion, a reasonable portfolio manager would not have made any procurement decisions based on the potential departure of this small level of load.⁴¹⁷ This perspective was confirmed by Mr. Wan on behalf of the Joint Utilities. He made clear that not all load departures would leave the utility with “excess supply.”⁴¹⁸ In fact, to have any impact, Mr. Wan concluded that the departure would need to be in the neighborhood of 10-20 percent.⁴¹⁹ Despite far more load departure than 10-20 percent, despite clear expectation from the Commission that the IOUs would adjust their procurement practices to address departing load, and despite clear obligations to minimize costs under Standard of Conduct No. 4, PG&E has done nothing to adjust its portfolio following the departure of CCA load until only very recently.⁴²⁰

Finally, nothing in the Joint Utilities’ strategies or Commission decisions provides for any exemption for departing load that was forecasted, contrary to the approach adopted in D.03-04-030. Thus, even if MEA’s load departure had been forecast in advance of procurement, there would be no basis for exemption under current rules.

While Marin Clean Energy is only one example, PG&E’s response to MCE’s formation demonstrates that PG&E’s strategy was to ignore CCA departing load in procurement and portfolio management, and to saddle these customers with additional costs. Marin Clean Energy’s customers departing in 2010 now unfairly bear the

⁴¹⁶ 5 Tr. 853:25-854:1 (Lawlor).

⁴¹⁷ 5 Tr. 855:5-9 (Lawlor).

⁴¹⁸ 1 Tr. 36:25-37:5 (Wan).

⁴¹⁹ 1 Tr. 37:17-21 (Wan).

⁴²⁰ 4 Tr. 822:24-28 (Lawlor).

uneconomic costs of contracts executed when PG&E had clear knowledge of their departures. And they bear this cost responsibility despite the fact that the departure did not create excess supply nor would have changed PG&E's procurement strategy in any way. These costs cannot be reasonably "attributable" to MCE in any sense of the word. Moreover, set in the context of the Commission's clear analysis in D.03-04-030, it is difficult to see PG&E's conduct as anything but unreasonable.⁴²¹ Either PG&E continues to hold all of these resources procured after MCE's departure (and any other similarly situated CCA) solely for the future benefit of its bundled ratepayers, or PG&E failed to act in accordance with state law and Commission decisions directed it to respond to these load departures for portfolio planning and management.

Only recently, in 2016, have PG&E and SCE begun to take a more reasonable approach for forecasting departing load. SCE has marginally increased flexibility in the timeline for forecasting departing load. As Mr. Hoekstra explained on behalf of CalCCA: "Before 2016, a specific CCA was excluded from SCE's bundled service forecast only upon the occurrence of: (1) start of CCA service or (2) filing of a binding notice of intent...."⁴²² Today, SCE also relies on a third criterion: participation in the CPUC's RA proceeding."⁴²³ SCE uses this information in stochastic modeling of

⁴²¹ PG&E's activities are also suspect given their ongoing campaign to thwart CCA formation which lead to SB 790 and the Code of Conduct. Only a hidebound utility can argue that load departure was not certain enough to be modeled within its procurement strategies or was too small to impact procurement, yet that same expended enormous corporate resources to fight MCE's formation with such a level of misinformation that the Legislature and then the Commission had to constrain it's behavior. Yet that is exactly what Witness Wan would have the Commission believe.

⁴²² Exh. CalCCA-1 at 3-12:20-21.

⁴²³ *Id.* at 3-12:17-19.

expected CCA load departure.⁴²⁴ Mr. Hoekstra noted that “PG&E likewise has more recently adopted a stochastic modeling approach to forecasting departing load.”⁴²⁵

While these changes are “a step in the right direction,” they are too little, too late for many departed customers and highlight the long-standing utility practice of ignoring the potential for CCA departing load – to the detriment of all customers responsible for uneconomic costs. The Commission should take several actions in response to these issues. First, the Commission should require the Joint Utilities to more aggressively anticipate departing load, rather than waiting for a binding notice of intent to account for the risk in its bundled load forecast. A reasonable portfolio manager should use “common sense” in forecasting departing load, as articulated in D.03-04-030. The utilities already used probabilistic methods for forecasting all other loads—they long ago abandoned straight-line trend forecasting methods, and certain customer groups, particularly large industrial and agricultural, exhibit volatile and uncertain load growth. Second, the Commission should provide for an exemption from contracts executed in a certain year up to the amount of departing load forecast for that year. If the utility excludes an amount of departing load in establishing its procurement plan, any procurement under the plan cannot reasonably be “attributable to” departing load up to the forecast departing load amount, as concluded by D.03-04-030. Third, the Commission should prohibit the Joint Utilities from imposing uneconomic costs for contracts executed *after* a customer departs, even if executed in the year of departure. It defies logic to conclude that such contracts are “attributable to” load that has already

⁴²⁴ *Id.* at 3-13:3-5.

⁴²⁵ *Id.* at 3-13:16-17.

departed. Finally, the Commission should require the Joint Utilities to prepare and file scenario-based assessments of the potential long-term range of future load departure and ensure that the resource plans and procurement commitments provide adequate flexibility to adapt to the resulting range of supply obligations many years into the future.

Mr. Hoekstra, on behalf of CalCCA, observed the importance of reasonable forecast “in avoiding unnecessary procurement and inappropriate attribution of the costs resulting from that procurement.”⁴²⁶ Forecasting, he continued “will mitigate the risk of excess long-term procurement...which in turn will minimize stranded assets and above-market costs.”⁴²⁷ He concluded that “[f]ailure to sufficiently recognize the departing load risk directionally results in over-procurement.”⁴²⁸ Taking action in improving the Joint Utilities approach to forecasting and the use of departing load forecasts is critical to fair stranded cost allocation and avoiding further accumulation of stranded costs.

B. The Commission Should Direct the Joint Utilities to Improve Portfolio Management Practices

The Joint Utilities “have a responsibility on behalf of *all customers* to minimize costs.”⁴²⁹

Notably, Standard of Conduct 4 provides:

In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs.⁴³⁰

The Joint Utilities agree that the Commission can disallow costs under a contract that has been approved by the Commission in cases where the utility has mismanaged that contract, typically

⁴²⁶ Exh. CalCCA-1 at 3-11:16-21.

⁴²⁷ *Id.*

⁴²⁸ *Id.*

⁴²⁹ 2 Tr. 322:14-14 (Cushnie) (emphasis supplied).

⁴³⁰ *Id.* at 2 (citing PG&E’s Approved Bundled Procurement Plan at page 26).

in the ERRA.⁴³¹ While CalCCA agrees with this conclusion, the ability to challenge utility contract or asset management in the ERRA proceeding remains subject to dispute, as discussed further below.

The Joint Utilities contend that they have made material efforts to manage their portfolios in the face of declining load.⁴³² CalCCA questions these efforts, observing that the utilities admit that by practice they make no adjustments to their procurement plans as a direct response to departing load, but manage on the basis of the total generation portfolio. (How the utilities account for changes in load is unclear from the record.) Moreover, the utilities made no material efforts to sell their long positions until early 2018 – conveniently right before testimony was filed in this proceeding. Finally, certain of the actions taken by the utility do not benefit *all* customers, but favor only bundled customers. CalCCA proposes measures that may improve these utility practices so that portfolio management is actively conducted on behalf of all customers.

1. Require the Joint Utilities to Actively Manage Their Portfolios in Response to Departing Load

The Joint Utilities have made clear that they do not modify their procurement plans in direct response to departing load, but generally manage procurement “in a bundled way.”⁴³³ For example, even if PG&E had binding notice of Marin’s departure on January 1, 2010, the utility would not have altered its procurement of RPS contracts.⁴³⁴ As Mr. Lawlor explained that “PG&E I think was at about, in 2010, 16 percent RPS. We would have continued to procure

⁴³¹ 2 Tr. 368:17-369:12 (Cushnie).

⁴³² Exh. IOU-1 at 3-2 through 3-4.

⁴³³ 4 Tr. 822:24-28 (Lawlor).

⁴³⁴ 4 Tr. 823:14-20 (Lawlor).

based on *the bundled total need*.”⁴³⁵ Failing to manage the portfolio in response to departing load can have economic consequences for departing load customers and muddles the issue of which costs are reasonably attributable to those customers.

Economic consequences for departing load customers arise in a declining price market. CalCCA witness Hoekstra observed that “[t]he utilities have had opportunities to sell assets, avoiding a continuing stranded cost, as customer departure has occurred.”⁴³⁶ Providing an example, he explained:

PG&E had the opportunity to sell a portion of its RPS portfolio to SCE and SDG&E in 2010 (and perhaps municipal utilities who also face an RPS mandate) as Marin Clean Energy (later MCE) exited bundled service. According to the Green Adder included in PG&E’s 2010 ERRA workpapers, a benchmark that is based on transactions for all three IOUs, PG&E could have sold MCE’s share of PG&E’s RPS portfolio for \$149/MWh. Similarly, the share for Sonoma Clean Power could have been sold in 2013 for \$120/MWh based on the reported ERRA index. Even if PG&E did not sell MCE’s and SCP’s portions immediately, the utility could have sold those portions for more than \$92/MWh at any point before 2017. Today, however, those resources are valued by the MPB at only \$82/MWh.⁴³⁷

He concluded that similar opportunities have been available as other CCAs exited and may be available going forward. If the utility could have sold that customer’s share – whether to a third-party or to the bundled portfolio – but elected not to make the sale, the ensuing accumulation of uneconomic costs is “avoidable” and cannot reasonably be “attributable to” the departing customer.

Two solutions present themselves. First, if the utility fails to sell the customer’s share of the portfolio in a declining price market, the Commission could deem that share as having been “sold to” the bundled load. This approach would be consistent with Mr. Lawlor’s testimony

⁴³⁵ *Id.* (emphasis supplied).

⁴³⁶ Exh. CalCCA-1 at 2A-6:1-2.

⁴³⁷ *Id.* at 2A-6:2-12.

concerning circumstances surrounding Marin’s departure; with full knowledge of Marin’s departure, PG&E would not have reduced its RPS procurement and executed the 2010 contracts and would still have procured the resources on behalf of bundled load.⁴³⁸ This approach is also consistent with PG&E’s approach spelled out in its “2016 Draft Renewable Energy Procurement Plan” in which continues to hold RPS-eligible PPAs for “managing the risk of being caught in a ‘seller’s market,’ where PG&E faces potentially high market prices in order to meet near-term compliance deadlines.”⁴³⁹

Alternatively, the Commission could set the benchmark for the departing customer’s share at the Green Adder for the customer’s year of departure.⁴⁴⁰ Given that these Green Adder represents the average of the market transaction prices for long-term procurement in that year, this is representative of the economic value to all ratepayers at that time. Bundled customers would be buying back the portfolio share from departed customers at the contemporary going price. This avoids any inappropriate ongoing failure-to-mitigate risk that is now arising as the utilities continue to manage the portfolio for both existing bundled customer load and now-departed customer load. The utilities are now retroactively truing up this departure transaction to mitigate the costs of their portfolios rather than managing those portfolios appropriately in the sole context of their bundled load. As Mr. Hoekstra explained “[i]n this way, the utilities will be given the correct incentive to reduce their portfolio holdings in a manner that maximizes the value for all ratepayers.”⁴⁴¹

⁴³⁸ 4 Tr. 823:14-20 (Lawlor).

⁴³⁹ 5 Tr. 901: 16-21 (McCann)

⁴⁴⁰ Exh. CalCCA-1 at 2A-7:1-2.

⁴⁴¹ Exh. CalCCA-1 at 2A-7:2-4.

2. Prohibit the Joint Utilities' Practices Aimed to Protect Shareholders and Bundled Ratepayers at Departing Load Customers' Expense

The Joint Utilities' policy witness, Mr. Wan, testified that interests of bundled and departing load customers are 100 percent aligned in portfolio management.⁴⁴² [REDACTED]

[REDACTED], however, tells a different story.⁴⁴³

CONFIDENTIAL Exhibit 102-C describes PG&E's Resource Adequacy Strategy for 2017 through 2018. PG&E's RA strategy highlights key risks and mitigations.⁴⁴⁴ The identification of risk reveals a point where interests diverge, requiring recognition in shaping the Joint Utilities' procurement practices.

The strategy identifies two risks that implicate divergent interests [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

⁴⁴² 1 Tr. 51:6-13.

⁴⁴³ CONFIDENTIAL Exh. CalCCA-102-C.

⁴⁴⁴ *Id.* at 2-4.

⁴⁴⁵ *Id.* at 3.

⁴⁴⁶ *Id.*

⁴⁴⁷ *Id.* at 4.

[REDACTED]

The memorandum goes further to point out diverging bundled and departing load customer interests. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Finally, the manner in which PG&E's strategy contemplates selling RA will affect the relative value to bundled and departing load customers. [REDACTED]

⁴⁴⁸ *Id.*, Table 1-A at 6. [REDACTED]

⁴⁴⁹ *Id.* at 5, n. 6.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] As Dr. McCann explained on behalf of CalCCA:

[U]tilities do hold those assets as hedges against future both reliability risk and price risk. So that there is an inherent value in holding those assets in excess of the short-term reserve margin requirements. [REDACTED]

Making short-term sales, however, does not yield prices that reflect the “full value” of the underlying resource, thus leaving excess value – value paid for by departing load customers – in the utility portfolio as a hedge for the benefit of future bundled requirements. Moreover, due to the deadlines for LSEs to submit their year-ahead and month-ahead RA compliance filings, waiting until the last minute to make short-term RA sales inevitably leads to the realization of little or no value because the value of RA declines precipitously at (or just before) these deadlines occur.

RPS procurement provides another example of the divergent interests of bundled customers and departing load customers. Dr. McCann explained that utilities use hedge values in determining their procurement plan and management of their portfolio. Dr. McCann quoted from PG&E’s 2016 Draft Renewable Energy Procurement Plan at page 19:

PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of, one, delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement, and two, managing the risk of being caught in a seller's market where PG&E's potentially high mark basis, potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with general need to manage overall RPS portfolio volatility based on demand and generation uncertainty,

450 *Id.* at 7.
451 *Id.* at 8.
452 5 Tr. 952:4-12 (McCann).

PG&E believes it is prudent and necessary to maintain an adequate bank, [that's the RPS bank], through the most cost-effective means available.⁴⁵³

While maintaining excess RPS hedges the future risk of bundled customers, the strategy may not be best suited for departing load customers. If, as discussed above, the Utility has the opportunity to sell a departing load customer's share of the portfolio RPS position in a declining market, but instead maintains the share in the portfolio, the Utility is benefitting bundled customers in hedging future risk at the expense of departing load customers.

This hedge value can be calculated using market data—it is the difference between the discounted future cost of continuing to hold the RPS PPAs and the current “mark to market” value of liquidating the contracts today. This is a market valuation of a clearly-identified and delineated benefit that accrues to bundled customers. Using the data from PG&E's ALJ Data Template,⁴⁵⁴ we can calculate the weighted average cost of the PG&E's RPS-eligible PPAs for 2018 to 2017, calculate the net present value of those PPAs using PG&E's weighted average cost of capital from its 2017 General Rate Case, and calculate the implied hedge premium by subtracting the current RPS market price benchmark from the 2018 PCIA. Based on those calculations, PG&E's market-based hedge valuation is [REDACTED]. [REDACTED]. CCA customers are left to pay for this hedge value that accrues solely to bundled customers, generating a subsidy to those customers. Meanwhile, CCA customers must build their own RPS portfolios that include hedging price risk, with no subsidies from bundled customers.

⁴⁵³ 5 Tr. 901:3-902:1 (McCann).

⁴⁵⁴ PG&E-Attachment 10 ALJ Requested Data Matrix MODIFIED CONFIDENTIAL.xlsx, sheet ALJ Template

The divergence of interests of bundled and departing load customers in the context of RPS procurement can also be seen in the context of Marin’s 2010 departure. Mr. Lawlor acknowledged that even if they had received their required indication that Marin customers were planning to depart in 2010, they would still have procured the contracts *on behalf of bundled load*. Effectively, PG&E was intent on pursuing its strategy for RPS procurement, and bundled customers got lucky enough to be able to offload the costs of the bundled strategy on departing load customers.⁴⁵⁵

The muddling of bundled and departing load interests, in both RA and RPS procurement policy, makes attribution of cost responsibility to departing load customers challenging, at best. Based on the evidence in this proceeding, the Joint Utilities are likely attributing cost responsibility to departing load customers for costs of resources that were not acquired for them and may have been avoidable at the time they were incurred. Even setting this issue aside, one change is necessary: departing load customers should not be paying for excess resources acquired or maintained to hedge bundled customers’ compliance and price risk.

One solution, for future procurement, was recommended in CalCCA’s opening testimony. In evaluating new resource commitments:

[T]he Commission should make three explicit determinations: (1) the expected effect of the commitment on the PCIA rate for all vintages of departing load; (2) whether the utility’s forecast of departing load was reasonable at the time the resource commitment was made; and (3) to which vintages of departing load the commitment is attributable.⁴⁵⁶

The Commission should similarly examine the role and impact of departing load in the context of the Joint Utilities’ Bundled Procurement Plans to assess the extent to which

⁴⁵⁵ *Id.* (emphasis supplied).

⁴⁵⁶ Exh. CalCCA-1 at 5-2:18-22.

those plans account for departing load and the extent of resources stranded by a customer's departure. While these measures are not complete solutions, they enable the Commission to make a focused inquiry to bring awareness to the potentially divergent interests of bundled and departing load customers.

Finally, the existence and ease of calculating the hedge premium for holding RPS PPAs to mitigate price risk on behalf of bundled customers should be included in the market valuation of the PCIA-eligible portfolio. This amount is additive to the Green Adder MPB in the PCIA until the SPA is implemented to reveal the full value of the utilities' portfolios.

3. Require the Joint Utilities to Optimize Sales from Their Portfolios to Capture the Full Value of the Resources for All Customers

The record is devoid of evidence demonstrating that the Joint Utilities have taken steps to optimize the value of their portfolios. All signs point to a strategy to procure and hold on to resources sufficient to meet all load in their territories except for the very minimum that is absolutely certain to depart in order to mitigate all potential RA or RPS compliance risk and then offload excess RA capacity in the short-term market or bank RPS credits until needed to serve bundled load at some point in the future. The apparent result is that the Joint Utilities intend to hold on to the resources in their portfolios as long as they can possibly just doing so, and then make limited adjustments in reaction only to the year-to-year changes that are known to occur with near-certainty. As with the Joint Utilities' misguided focus on short-term departing load forecasts discussed above, this portfolio management strategy wastes value in the portfolio and fails to adequately mitigate excess costs in the portfolio for the benefit of departing load customers. This strategy retains for bundled customers, to the exclusion of benefiting departing load customers, the hedge value and the value of optionality, market information and other long-

term attributes that are actually inherent in the supply portfolios, yielding an artificially depressed “market” value for a different, much more limited product.

Until shortly before testimony was due in this proceeding, the Joint Utilities had not engaged in forward sales of more than one year.⁴⁵⁷ failing to realize the full value of the long-term resources embedded in the portfolio. The recent sales processes conducted by PG&E appear to have been intended primarily to meet a regulatory need, and were insufficient in both their design and administration to maximize the value of the products being sold from the portfolio.⁴⁵⁸

a) Sell Resources on a Long-Term Basis With All Value Intact

It is readily apparent that the Joint Utilities should be evaluating and managing their portfolios from the perspective that their long-term bundled load customers’ requirements have been substantially and permanently reduced by load departures that range from 35 or 40 percent now up to 85 percent at some point into the future.⁴⁵⁹ But as discussed above, there is no evidence that the Joint Utilities have embraced that reality, whether in their departing load forecasting practices, in their resource planning and procurement decisions, or in their portfolio management decisions. It is time for the Commission to give the Joint Utilities explicit guidance and direction on steps they should be taking to correct those past mistakes.

First and foremost, the Commission should direct the utilities to engage in long-term forward sales transactions in order to flatten their substantially long (excess supply) positions and extract maximum long-term value for those resources. The short-term incrementalism in which the Joint Utilities are currently engaged is clearly failing to achieve these objectives.

⁴⁵⁷ Exh. CalCCA-3 at 3-1 to 3-5.

⁴⁵⁸ Exh. CalCCA-3 at 3-3:28 to 3-4:47.

⁴⁵⁹ Exh. IOU-1 at 1-1:19-28.

The Structured Portfolio Auction (SPA) proposal is CalCCA's preferred approach to implement a long-term sale of portfolio attributes, and is the only alternative presented in this case that is reasonably designed to maintain, capture and maximize the long-term value of the resource attributes in the Joint Utilities' portfolios. CalCCA urges the Commission to adopt the SPA proposal in concept and, in a subsequent phase of this proceeding, design and implement the detailed auction scope and protocols to permit the long-term sales to be achieved.

b) Sell Resources Subject to Reasonable Terms and Conditions.

Regardless of the means by which the resources are offered, the terms and conditions of the offers must be developed in a way that is most likely to maximize the interest of the market (including CCAs) and thereby maximize the value of the offering. Interest in the auction will be influenced by the way in which products are offered, including:

- The number of projects/contracts and type of resources being offered;
- Timing of RFO issuance and bid due dates relative to ongoing procurement schedules;
- Product structure, e.g., allowing for fixed price contracts with specified or preferred hourly delivery profiles to allow participants to capture the energy value for load hedging;
- Scope of information provided to develop detailed analysis of specific projects, e.g., information on P-Node locations to garner premiums based on geographic preferences, congestions issues, etc.

The utilities should solicit input from potential market participants to ensure ratepayers receive the highest price for the products offered to the market.⁴⁶⁰

⁴⁶⁰ Exh. CalCCA-1 at 3-14:9-24 (directly quoted).

c) Require Revintaging of a Contract If the Utility Fails to Exercise a Right to Terminate the Contract or Otherwise Extends the Contract.

The relevant departing load cost responsibility statutes require the Commission to assess charges only for procurement costs that are “unavoidable” by the utility acting on behalf of its customers. The Joint Utilities have encountered in the past, and will continue encounter in the future, opportunities to avoid costs under their PPAs will suppliers through the prudent exercise and leveraging of all contract rights and remedies to which they are entitled.⁴⁶¹ Under such circumstances, departing load vintages require modification. If the utility is presented with an opportunity to end an existing contract obligation, that opportunity should mark a new procurement date because that procurement decision would not have been made on behalf of previously departed or imminently departing customers. Continuing to rely on the initial execution date to vintage the contract fails to acknowledge when an irrevocable decision has been made on behalf of a customer and the costs become “unavoidable.”⁴⁶²

X. THE COMMISSION SHOULD DIRECT THE UTILITIES TO USE THEIR BEST EFFORTS TO REDUCE PORTFOLIO COSTS USING SECURITIZATION OF UOG ASSETS AND CONTRACT BUYDOWN TRANSACTIONS (Common Outline §VII)

In the face of an estimated \$49.68 billion in uneconomic portfolio costs over the next 22 years, the Commission and bundled and departing load customers have the right to expect the utilities to make all reasonable efforts – indeed, *best efforts* – to reduce their total portfolio costs. Yet only CalCCA, on behalf of its members’ ratepayers, proposed any material cost reduction measures in this proceeding. In addition to changes to optimize portfolio value, discussed in Section IX, CalCCA proposes two measures aimed at more significant, long-term savings.

⁴⁶¹ *See id.* at 3-15 to 3-16.

⁴⁶² Exhibit CalCCA-1 at 3-15 to 3-16.

Material cost reductions could be achieved if the Joint Utilities refinanced their UOG assets through sales of low-interest bonds securitized by a dedicated rate component. These savings arise primarily from a reduction in financing costs from the utility weighted average cost of capital to the bond rates, levelization of the revenue requirement and a reduction in income taxes.⁴⁶³ As discussed below, this measure could produce PCIA-eligible cost savings, on a net present value basis, of \$1.3 billion for PG&E and \$589 million for SCE.⁴⁶⁴ In the first year, securitization could achieve a savings of \$496 million for PG&E and \$130 million for SCE compared with a traditional revenue requirement.⁴⁶⁵

Material cost reductions may also be achievable through buydown or price reductions in long-term PPAs. CalCCA proposes a voluntary reverse RFO, under which the utility, under Commission guidance, would invite offers for price reductions and select the offers providing the best value to the portfolio.⁴⁶⁶ As CalCCA witness Robert Kinosian explained, “[g]enerators may be willing to provide a significant reduction in the contract costs if they place a higher value than the utilities’ ratepayers do on an immediate payment rather than earn contracted revenues over time.”⁴⁶⁷ For example, “a reduction of \$100 million/year for 20 years in contract payments provides ratepayers with a \$2 billion nominal savings over 20 years.”⁴⁶⁸ Discounting these savings using the utilities’ weighted average cost of capital yields a net present value savings of approximately \$1 billion to bundled and departing load customers.⁴⁶⁹

⁴⁶³ See Exh. CalCCA-1, Exhibit 3-A, Ex. K.

⁴⁶⁴ Exh. CalCCA-1 at 3-7:7-9.

⁴⁶⁵ See *id.*, Exhibit 3-A. These values were derived, for PG&E, by comparing the 2019 revenue requirement values from Ex. I, p. 2 and Ex. H, p. 2 and, for SCE, by comparing the 2019 revenue requirement values from Ex. I, p. 3 and Ex. H, p. 2

⁴⁶⁶ Exh. CalCCA-1 at 3-9:8-16.

⁴⁶⁷ *Id.*

⁴⁶⁸ Exh. CalCCA-1 at 3-8:3-4.

⁴⁶⁹ *Id.* at 3-8:4-7.

Electric utility securitization has been used by investor-owned utilities as a taxable debt financing tool at least 64 times since 1997.⁴⁷⁰ Indeed, it is not a new concept in California. The Legislature and Commission have twice previously authorized the issuance of this type of debt.⁴⁷¹ Both the Legislature and this Commission will easily be able to draw on these experiences as precedents for a new securitization program, updated to incorporate current best practices and examples set by other states.⁴⁷² Facing roughly \$50 billion in uneconomic portfolio costs for the next 22 years, the utilities should strongly be encouraged to make use of securitization to reduce the magnitude of these costs.

Assuming securitization is available to the utilities, it renders some portion of the current financing costs for UOG at the utility's weighted cost of capital assets "avoidable." Consequently, to the extent the utilities elect *not* to employ securitization, the Commission should reduce the return on UOG assets paid through the PCIA to the cost of debt, since only "unavoidable" costs may be recovered from departing load.

A. Securitization is a Low-Cost Financing Tool That Has Been Used in the Utility Industry

Securitization is a financing tool that has been used to facilitate several types of transitions in markets, and to eliminate rate "shocks" that could potentially have occurred in certain markets.⁴⁷³ "Securitization" describes a process by which a pool of assets that generate a cash flow, such as loans, credit card balances or other receivables, is used as collateral for a bond offering. In the utility context, the bond proceeds are used to meet retire a ratepayer obligation, such as generation asset rate base or a contract buydown. The cash flow securing the bonds,

⁴⁷⁰ Exh. CalCCA-1, Exhibit 3-A, at 6.

⁴⁷¹ Exh. CalCCA-1, Exhibit 3-C, at 8-10.

⁴⁷² 4 Tr. 691: 11-20 (Fischera).

⁴⁷³ 4 Tr. 664: 14-18 (Fischera); 4 Tr. 671: 1-25 (Sutherland).

typically a dedicated rate component in the utility context, is then used to pay principal and interest on the bonds.

For investor-owned electric utilities, securitization typically involves issuing highly-rated securities through special purpose, bankruptcy remote/ring fenced entities. In the unusual scenario, it is a specific legislatively enabled and regulatory approved process through which a special purpose legal entity (SPE), which is protected from any credit problems of the utility, receives from the utility the entire right, title and interest in certain assets that are then pledged to the repayment of the securities.⁴⁷⁴ The SPE, whose sole purpose is strictly limited to owning the pledged assets and paying the principal and interest on its bonds, issues securities backed by the transferred assets. The cash flows from those pledged assets are used to pay principal and interest on the bonds. The carrying costs of the securitized debt are much less than the costs that would be incurred using traditional utility financing methods of debt and equity, which is often called the utility's "weighted average cost of capital" (WACC).⁴⁷⁵ Although the pledged assets can be physical (such as plant and equipment), frequently the asset transferred to the SPE is the collection by the utility of a commission-approved and periodically adjusted dedicated rate component.

The SPE and the securities it issues are perceived to carry much less risk than standard utility corporate debt and are therefore attractive to investors at a lower cost to the utility.⁴⁷⁶ To the investor, the bond issue is a direct borrowing on the utility's customer rate base in its distribution territory without involving the utility's balance sheet for credit purposes or

⁴⁷⁴ Exh. CalCCA-1, Exhibit 3-A, at 5.

⁴⁷⁵ *Id.* at 6.

⁴⁷⁶ *Id.*

comingling with the utility's other creditors.⁴⁷⁷ For the utility, securitization increases cash flow and achieves a lower cost of capital than traditional means. Securitization offers added benefits beyond the differences in the cost of capital. Because it reduces utility income, the process also reduces income taxes, including income-based state franchise taxes, as well as revenue-based local franchise fees. In addition, securitization levelizes debt carrying charges, shifting more costs into later years. This creates a NPV benefit.

In each state where utility securitization bonds have been issued, specific enabling legislation created in the utility the right to impose, adjust, bill and collect amounts from electric customers in a given service territory.⁴⁷⁸ Then the relevant utility commission issued an irrevocable financing order imposing a specific charge on customers to implement the legislation. Because of this, the bonds have often been called ratepayer-backed bonds or ratepayer obligation charge (ROC) bonds and even rate reduction bonds (RRB), among other terms.⁴⁷⁹

Utility securitization bonds as described here are frequently confused with other types of “asset backed securities” (ABS). However, while there are common features, utility securitization bonds are generally considered much more “creditworthy” than typical ABS issues, and are decidedly unlike common ABS.⁴⁸⁰ The major difference in creditworthiness is due to three factors: the regulatory nature of the asset in question, the ability for joint and several collection, and the nonbypassable feature of the charge that supports the debt.

⁴⁷⁷

Id.

⁴⁷⁸ Exh. CalCCA-1, Exhibit 3-C, at 8.

⁴⁷⁹ *Id.* at 6.

⁴⁸⁰ Exh. CalCCA-1, Exhibit 3-A, at 13.

Securitized utility bonds are backed by an enforceable regulatory right, not by a contract right or pool of receivables or other assets. This is an important distinction, and for this reason, the Office of Chief Accountant of the U.S. Securities and Exchange Commission (SEC) has directed that the type of securitized utility bonds under discussion here not be treated as “asset-backed securities” for purposes of Regulation AB (ABS offering regulations).⁴⁸¹ In addition, unlike a general pool of assets supporting an issue of ABS, the regulatory asset created by the legislation is collectible from remaining customers even if some customers no longer receive electric transmission or distribution service, or fail to pay the charge. This again is a material difference. Finally, the legislation and the utility commission’s financing order create a nonbypassable charge to secure bond repayment.⁴⁸² Generally, the financing order issued by the regulator is irrevocable and cannot be revisited at any time during the life of the bonds.⁴⁸³

B. Securitization Reduces Portfolio Costs

Securitization saves money for utility ratepayers in several ways. First, the cost of equity is much higher than the cost of debt.⁴⁸⁴ In addition, securitized ratepayer-backed bonds pay lower interest than even traditional utility debt, due to their extremely high credit quality.⁴⁸⁵ With the SPE’s better credit rating, the bonds can be issued with a lower interest cost. For example and as detailed in CalCCA’s testimony, while PG&E’s authorized cost of equity is 10.25%, the securitization debt at current levels would likely bear an interest rate of only about 3.91%.⁴⁸⁶ In the case of SCE, the utility’s authorized cost of equity is 10.3%. Securitized debt, on the other

⁴⁸¹ *Id.* at 11.

⁴⁸² *Id.* at 14.

⁴⁸³ *Id.*

⁴⁸⁴ Exh. CalCCA-1, Exhibit 3-A, at 21.

⁴⁸⁵ *Id.*

⁴⁸⁶ Exh. CalCCA-1, Exhibit 3-A, at 25.

hand, is estimated to likely cost only about 4.07%.⁴⁸⁷ These savings would accrue directly to the ratepayers in the form of lower overall rates than would otherwise be levied.

The second largest contributor to savings is in the avoidance of income taxes that would otherwise have to be paid on the equity return.⁴⁸⁸ When the Federal tax rate of 21% is combined with the 8.84% rate for California income-based franchise taxes, the effective composite income tax rate is 28%. With securitization financing, there are no income-based taxes. Because income related taxes are directly related to the utility earning a taxable equity return. With no equity, there will be no income tax payable.⁴⁸⁹ In addition, there are savings from the fact that revenue-based fees, such as local franchise fees, would be slightly less.

The third major contributor to savings is the levelization of the revenue requirements. Traditional ratemaking requires the ratepayer to pay much more in the early years of an asset's useful life and much less in the later years.⁴⁹⁰ Securitization financing allows the ratepayer to pay a levelized amount throughout the life of the assets in question. By levelizing the payments that are financed with inexpensive debt rather than front-end loading revenue requirements, the NPV savings, when discounted at the utility cost of capital (7.69% and 7.61% for PG&E and SCE, respectively), are increased substantially.⁴⁹¹ This accounts for about 23% of the \$1.6 billion total NPV savings that is estimated for PG&E ratepayers. For SCE, levelization accounts for 15% of the \$589 million total NPV savings.⁴⁹²

⁴⁸⁷

Id.

⁴⁸⁸

Id.

⁴⁸⁹

4 Tr. 672: 22-26 (Sutherland).

⁴⁹⁰

Exh. CalCCA-1, Exhibit 3-A, at 24.

⁴⁹¹

Id.

⁴⁹²

Id. at 25.

In fact, the rating agency Moody's has explicitly stated that securitization benefits the utility, as well as the ratepayers.⁴⁹³ Although the utility gives up the opportunity to earn a return on the corresponding asset, the utility receives an immediate source of cash, which it will simply invest in other ways.⁴⁹⁴ In addition to all of the benefits detailed above, securitization may offer greater potential benefits to PG&E and its customers in light of recent downgrades of its debt. PG&E could use lower-cost capital raised by securitization either in response to storm damage or wild fire response, or to pay down higher cost debt, thereby potentially causing its credit rating to increase as its debt-to-equity ratio decreases. The restoration and strengthening of PG&E as an investment grade company may be considered vital to the company's future ability to service its customers.

C. Securitization of Utility Owned Generation Would Produce Substantial Cost Reductions for Bundled and Departing Load Customers

CalCCA proposes the Commission move forward with a program to securitize the rate base of all UOG intended to remain in the utilities' PCIA-eligible portfolio for their remaining service lives. Securitization offers an opportunity to reduce the costs of resources in the utilities' PCIA-eligible portfolios for all customers responsible for paying the PCIA, including bundled, community choice aggregation (CCA) and direct access (DA) customers. Securitization would significantly reduce the cost to ratepayers in paying off the existing rate base as compared to the typical depreciation and cost of recovery process.⁴⁹⁵ Importantly, securitization would not change the ownership or operation of the facilities, which would continue to be owned and operated by the utilities. Aside from current rate base, additional costs

⁴⁹³ 4 Tr. 701: 4-10 (Abramson).

⁴⁹⁴ 4 Tr. 701: 4-10; 699: 27-28 (Abramson).

⁴⁹⁵ 4 Tr. 661: 24-28 (Fischera).

of the generation plants, such as fuel, O&M, A&G and capital additions, would continue to be addressed in standard Commission proceedings and recovered under standard Commission revenue recovery methods.⁴⁹⁶

The proposal would be implemented through a bond issuance of capital sufficient to repay the utilities for their remaining investment in their generation facilities, the generation rate base, which is currently calculated at approximately \$4.2 billion for PG&E and \$1.5 billion for SCE.⁴⁹⁷ The current revenue requirements associated with the rate base (depreciation, WACC and taxes on income) would be replaced by the lower interest and principal payments on the securitized bonds. This would provide an initial estimated decrease in the amount charged to bundled customers of more than 50%.⁴⁹⁸ In addition to the direct savings to bundled customers, the reduction in generation revenue requirements will also reduce the forecasted uneconomic costs of the utilities' generation portfolios, thereby reducing the PCIA.

If a securitization strategy were undertaken, cash realized by the utility could be used to either pay down other, more expensive, utility debt, or to free up debt and equity capital for other important projects, such as planned capital expenditures, emergency funds or extraordinary expenses. The utility's revenue requirement would decrease, resulting in savings to ratepayers. Securitizing all or a portion of the existing UOG rate base would reduce financing costs to all ratepayers. Securitization of the utilities' PCIA-eligible portfolios, excluding fossil intended to be removed from this portfolio after 10 years under D.08-09-012, could produce PCIA-eligible cost savings, on a net present value basis, of \$1.3 billion for PG&E and \$589 million for SCE.⁴⁹⁹

⁴⁹⁶ Exh. CalCCA-1, at 3-7.

⁴⁹⁷ *Id.* at 3-6.

⁴⁹⁸ *Id.* at 3-7.

⁴⁹⁹ Exh. CalCCA-1 at 3-7:7-9.

In the first year alone, securitization would achieve savings for bundled and departing load customers of \$496 million for PG&E and \$130 million for SCE compared with a traditional revenue requirement.⁵⁰⁰

D. Voluntary Reverse RFO and Securitized Buydown of PCIA-Eligible PPAs Could Further Reduce Costs

Much has been made elsewhere in this proceeding of the extreme decreases in the price of renewable energy, and the reasons behind the utilities' entry into these now high-priced contracts. These are generally long-term contracts (some for 20-25 years) at set quantities and at set prices which now exceed current and expected future market prices. Some of these contracts call for the utilities to purchase power at rates as high as 18 cents/KWH or more.⁵⁰¹ Encouraging price reductions in these contracts from willing counterparties in exchange for up-front payments, and securitizing the financing of these reductions, could materially reduce PCIA-eligible costs. The up-front, lump-sum amounts for the buydown would be paid off through securitization, as opposed to either expensing them in one year, which might result in rate shock, or having them paid off over time at the utility's rate of return.⁵⁰² Securitizing contract buydowns, while less common than other types of securitization used with respect to utilities, has been used in other states. It was successfully implemented in New Hampshire and authorized for use in Vermont.⁵⁰³ It is a tested, successful method that could benefit California ratepayers.

⁵⁰⁰ See *id.*, Exhibit 3-A. These values were derived, for PG&E, by comparing the 2019 revenue requirement values from Ex. I, p. 2 and Ex. H, p. 2 and, for SCE, by comparing the 2019 revenue requirement values from Ex. I, p. 3 and Ex. H, p. 2.

⁵⁰¹ *Id.* at 28.

⁵⁰² 4 Tr. 662: 9-14 (Fischer).

⁵⁰³ 4 Tr. 674: 21-25 (Sutherland); Exh. CalCCA-1, Exhibit 3-A, at 29.

CalCCA proposes that willing generators be paid an up-front lump sum in exchange for reducing the contract price for generation in future years, *i.e.* buying down the contract price.⁵⁰⁴ The funds used to pay the generators would come from the issue of securitized debt. The buydown may be extremely attractive to generators, who may be willing to provide a significant reduction in the contract costs, if they place a higher value than the utilities' ratepayers do on an immediate cash payment rather than earn contracted revenues over time. In financial terms, this is the case if the generators use a higher discount rate for discounting future cash flows than utility ratepayers.⁵⁰⁵ As CalCCA has proposed the process, the price reduction would be the only change, and all other terms of the PPA would remain in effect.

If, for example, an average price reduction of 13.5 cents per kWh for 2,000 GWh/year of purchased power was achieved by a buydown of eligible contracts (from 18.5 cents/kWh to 5 cent/kWh), it would, when netted against a levelized 20-year securitized bond payment of \$187.6 million (9.4 cents/kWh), result in a net savings of \$72.4 million (3.6 cents/kWh) in the first year.⁵⁰⁶ Such a restructuring could result in NPV savings to bundled, CCA and DA ratepayers of \$449 million.⁵⁰⁷

Additional savings may also be possible, depending on the generators' willingness to accept a buydown, which will be driven in large part by each generator's individual discount rate. Discount rates of 10% and 12% show a potential reduction of \$850 million and \$750 million respectively compared to the utilities' weighted cost of capital.⁵⁰⁸ This disparity in buyer

⁵⁰⁴ Exh. CalCCA-1 at 3-9:8-16.

⁵⁰⁵ Exh. CalCCA-1, at 3-8.

⁵⁰⁶ Exh. CalCCA-1, Exhibit 3-A, at Exhibit P.

⁵⁰⁷ *Id.*

⁵⁰⁸ *Id.*

and seller discount rates provides potential opportunities for mutually beneficial, voluntary contract buydown transactions for existing RPS-eligible PPAs.

Securitization of contract buydown costs increases the potential for ratepayer savings with buydowns because the up-front payment would be financed at a rate much lower than the utilities' weighted cost of capital, 3% to 4% compared to 7.5%. For example, if the developer's discount rate is 15% and the utility's securitized debt rate is 4%, there is a great deal of room for negotiation that would benefit ratepayers. There would be less room if the difference were that developer's discount rate and the utility's weighted average cost of capital of, say, 7.5%.⁵⁰⁹

In addition to benefitting ratepayers, both buydown, and securitization of the buydown, of these contracts could also benefit the utilities in significant ways. In recent years, credit rating agencies have begun to analyze long-term PPAs as though they were, in part, debt of the purchasing utility. The Commission has studied the phenomenon⁵¹⁰ This exposes PCG/PG&E and EIX/SCE to risk that the credit ratings on their other debt and equity securities will be reduced.⁵¹¹ If the annual payment obligations of PG&E and of SCE are reduced by a buydown financed by a securitization, this "debt equivalence" concern should be significantly mitigated if PG&E's and SCE's.

In order to address certain concerns raised by commentators regarding a buydown solution, CalCCA proposes that a reverse Request for Offers mechanism be implemented to identify generators wishing to participate, and to provide for Commission-established metrics

⁵⁰⁹ Exh. CalCCA-1 at 3-9.

⁵¹⁰ *An Introduction to Debt Equivalency*, California Public Utilities Commission, Policy & Planning Division, August 4, 2017.

⁵¹¹ Exh. CalCCA-1, Exh. 3-A, at 31.

and parameters applicable to the program.⁵¹² For example, the Commission could identify an amount of funding available for the RFO to buy down contract prices. The utility would then issue an RFO soliciting proposals from generators for contract price reductions. The generators offering the largest NPV discounts per dollar of upfront funding, perhaps subject to a floor set by the Commission, would be awarded a buydown.

Limiting negotiation to only price reduction per kWh, which should allay any ratepayer concerns about the utilities negotiating transactions without clear guidance and boundaries.⁵¹³ The program should be entirely voluntary, so no generators should feel compelled to modify their existing contracts. Because generators must compete with each other to ensure they are one of the winning bids, reasonable discounts are highly probable. Finally, CalCCA is proposing, as has been done in other states, that the authority to issue bonds be issued prior to the RFO.⁵¹⁴ Bonds themselves would be issued only if the RFO determines that there are bids offering saving significant enough for the buydown.⁵¹⁵ Thus, any potential concern regarding the unknown amount of savings is alleviated- the bonds will simply not be issued unless there are willing takers and the savings make sense for the state. The potential savings to all ratepayers by using securitization to fund a buydown of existing high-priced energy contracts merits robust consideration.

E. Limitations on the Utilities’ Ability to Employ Securitization Would Not Be Triggered by CalCCA’s Proposal

Certain commentators have raised concerns that securitization would negatively affect the utilities’ financing capacity. Although no figures were proposed for how much “capacity” is

⁵¹² *Id.* at 3-9:5-8.

⁵¹³ Exh. CalCCA-1 at 3-(;5-8.

⁵¹⁴ 4 Tr. 682: 23-28; 683:1.

⁵¹⁵ *Id.*

required, or how much would be affected by securitization, concerns were raised that securitization will affect the utilities' "head room" to increase rates for other purposes.⁵¹⁶ It has also been stated that securitization should be "saved" in case it is needed to address other issues the utilities may encounter 3 or 5 years from now, possibly as a result of major impacts to infrastructure and the markets by climate change or other forces.⁵¹⁷ However, any charge that would be implemented due to UOG securitization as proposed by CalCCA would result in approximately 5% of a total bill.⁵¹⁸ This is four times less than the general rule of thumb used that identifies charges of 20% or even 25% of a total bill as derogatory to financing capacity.⁵¹⁹ Moreover, the amount of securitization proposed by CalCCA in this proceeding is much lower as a percentage of utilities' revenues, than was securitized successfully twice before.⁵²⁰ In addition, given that the securitization CalCCA has proposed would itself lower the overall risk of the utility, investors should consider it a benefit, not a negative.⁵²¹

F. Securitization Examples

Other states have authorized the issuance of securitized bonds for investor-owned electric utilities for a variety of reasons, the four primary reasons of which include efforts to : recover operating costs incurred in the past for which future rate relief would be required, otherwise resulting in sharp rate increases for consumers, recovery of costs for electric supply service which are higher than the market, stranded costs' recovery, and financing of increased expenditures for new technologies requiring rate increases.⁵²²

⁵¹⁶ 4 Tr. 685: 23-28, 686:1-2 (Fischera).

⁵¹⁷ 4 Tr. 712: 11-12; 709: 15-23 (Patterson).

⁵¹⁸ 4 Tr. 687: 1-8 (Fischera).

⁵¹⁹ 4 Tr. 687: 19-26 (Fischera).

⁵²⁰ 4 Tr. 688: 25-28 (Kinoshian).

⁵²¹ 4 Tr. 684: 1-6 (Abramson).

⁵²² Exh. CalCCA-1, Exh. 3-D, at 5.

In Florida, the utility financed unrecovered costs of a nuclear plant that was retired early.⁵²³ In New Jersey, Maryland, Ohio, and West Virginia, regulatory assets representing deferred balances were securitized, while in Pennsylvania, Texas, New Hampshire, Illinois, Montana, Massachusetts, New Jersey, Michigan, Connecticut, and Louisiana, stranded costs in connection with electric industry deregulation were financed through this process. Storm recovery costs (Florida, Louisiana, Texas, Arkansas), costs of new pollution control equipment at existing electric generating facilities (West Virginia, Wisconsin), and costs of new renewable distributed generation (Hawaii) have also all been financed through securitization.⁵²⁴ The commissions in Texas, New Jersey, Michigan, Maryland, Louisiana, Ohio, West Virginia and Florida all have been actively involved in the structuring, marketing and pricing of securitized utility bonds.⁵²⁵

California itself already has a history of successful utility cost securitization efforts. Assembly Bill 1890 (Statutes of 1996, Chapter 854), California's sweeping electric industry restructuring law enacted in 1996, authorized securitization for California's investor-owned electric utilities.⁵²⁶ The legislature authorized the issuance of securitized Rate Reduction Bonds to finance a 10% rate reduction for residential and small commercial customers of California investor-owned utilities until they recovered the above-market costs of their generation-related assets. Pursuant to Financing Orders issued by the CPUC under authority of AB 1890, securitized Rate Reduction Bonds were issued for the benefit of PG&E (\$2,901 million in 1997),

⁵²³ *Id.* at 3.

⁵²⁴ Exh. CalCCA-1, Exh. 3-C, at 10.

⁵²⁵ *Id.* at 21.

⁵²⁶ *Id.* at 8.

SCE (\$2,463 million in 1997), San Diego Gas & Electric Company (“SDG&E”) (\$658 million in 1997) and Sierra Pacific Power Company (\$24 million in 1999).⁵²⁷

Then in January 2001, Governor Davis directed the state Department of Water Resources (DWR) to enter into contracts for the purchase and sale of electric power to assist in mitigating the effects of the emergency.⁵²⁸ Under authority of the Governor’s proclamation, related executive orders, and legislation enacted in 2001, and pursuant to CPUC orders issued in response to that legislation, DWR implemented a program to supply to the customers of each utility the portion of their electric power not provided by that utility (the “Net Short”). DWR initially borrowed more than \$10 billion to fund its purchases of electric power to cover the utilities’ Net Short.⁵²⁹

In 2002, representatives of DWR and the CPUC executed a rate agreement under which the CPUC promised to impose and periodically adjust (i) a Power Charge to recover DWR’s ongoing power supply expenses; and (ii) a Bond Charge to produce revenues sufficient to pay scheduled principal and interest on Power Supply Revenue Bonds issued by DWR.⁵³⁰ DWR issued Power Supply Revenue Bonds in several series to refinance much of the initial DWR borrowings. Those Power Supply Revenue Bonds have a final maturity date of May 1, 2022 and are payable primarily from Bond Charges.⁵³¹ In the rate agreement, the CPUC covenanted to calculate, revise, and impose Bond Charges sufficient to pay debt service on the Power Supply Revenue when due. DWR has pledged and assigned its revenues from Bond Charges for the payment of debt service on the Power Supply Revenue Bonds when due, subject to the possible

⁵²⁷ *Id.* at 8-9.

⁵²⁸ *Id.* at 9.

⁵²⁹ *Id.*

⁵³⁰ *Id.*

⁵³¹ Exh. CalCCA-1, Exh. 3-C, at 10.

prior use of revenues from Bond Charges to pay amounts due under certain priority long-term power contracts.⁵³²

In 2005, the Public Utilities Code was amended to authorize PG&E to issue \$3.0 billion of securitized energy recovery bonds to refinance a bankruptcy- related regulatory asset.⁵³³

Securitization provided the necessary cash flow to allow PG&E to emerge from bankruptcy and over time gain a more favorable credit rating which would then reduce its cost of capital.

Consumer groups proposed the refinancing of this “regulatory asset” with securitization, in essence giving the cash to PG&E up front in return for a reduced cost of carry for the regulatory asset. CPUC Decision No. 03-12-035 initially established that regulatory asset in the amount of \$3.0 billion, with the proviso that the amount was to be reduced to the extent PG&E in the future received energy supplier refunds arising in connection with the 2000-2011 energy crisis.⁵³⁴

In its testimony CalCCA presented a set of “best practices” recommended for a securitization effort.⁵³⁵ Many of these “best practices” concern the continued and active involvement of the utility commission in the authorization and monitoring of a security issuance. In fact, California’s prior history with securitization indicates the Commission’s expertise in implementing these practices. In the Financing Order (Decision No. 04-11-015) authorizing the issuance of Energy Recovery Bonds for PG&E, the CPUC was actively involved in the structuring, marketing, and pricing of past issuances of securitized utility bonds.⁵³⁶ For example, the Financing Order included the following Ordering Paragraph 33:

⁵³²

Id.

⁵³³ Exh. CalCCA-1, Exh. 3-D, at 7.

⁵³⁴ Exh CalCCA-1, Exh. 3-A, at 19.

⁵³⁵ Exh. CalCCA-1, Exh. 3-C.

⁵³⁶ *Id.* at 21.

“Prior to the issuance of each series of Energy Recovery Bonds, the Bonds and the associated Bond transaction shall be reviewed and approved by the Commission’s Financing Team consisting of the Commission’s General Counsel, the Director of the Energy Division, other Commission staff, outside bond counsel, and any other outside experts that the Financing Team deems necessary. The other outside expertise may include, for example, an independent financial advisor to assist the Financing Team in overseeing and reviewing the issuance of each series of Bonds. The Financing Team’s approval of each series of Bonds shall be evidenced by a letter from the Financing Team to PG&E. Any costs incurred by the Financing Team in connection with its review and approval of each series of Bonds shall be treated as a Bond issuance cost.”

Using securitization to fund PPA buydowns is, as noted, not as common. It has been adopted as a preferred method. In Vermont in 1999 the Vermont Electric Power Producers (VEPP Inc.) attempted to buy down PPAs that were priced as high as 17.5 cents/KWH.⁵³⁷ Although the state legislature passed enabling legislation to authorize securitization for this purpose, VEPP Inc. was never able to execute the buy downs at prices that created ratepayer savings, and securitized bonds, therefore, were not issued. However, in April 2001 and again in January 2002, Public Service Company of New Hampshire issued Rate Reduction Bonds for reducing its capitalization and buying down high-cost PPAs.⁵³⁸

Given California’s successful history with utility cost securitization, CalCCA urges the Commission to proceed with either or both proposals. Whichever scenario the Commission, utilities and stakeholders elect to pursue, securitization will deliver value to ratepayers, the utility, and the state in reducing procurement costs and continuing to transition to a more competitive environment.

⁵³⁷ Exh. CalCCA-1, Exh. 3-A, at 29.
⁵³⁸ *Id.*

XI. OTHER ISSUES (Common Outline §VIII)

A. The Commission Should Authorize Prepayment of Departing Load Cost Responsibility

The current PCIA is volatile, difficult to forecast and not calculated in a transparent manner and monitoring the PCIA requires ongoing regulatory intervention. The Commission could address these challenges and bring certainty and predictability to CCA and DA customers by permitting CCA and DA providers to prepay all or a portion of their customers' stranded cost obligation. Prepayment would entail an LSE paying the net present value of its future net obligations to the utility based on the LSE's load and vintage. It would protect both CCAs and utilities from ongoing uncertainty regarding the amount and timing of stranded-asset cost obligations. LSEs considering formation could accurately assess and potentially finance their customer's future obligations to the incumbent utility. The concept of Prepayment is also supported by AREM/DACC as set forth in Mark Fulmer's testimony⁵³⁹.

A viable prepayment option requires a clear methodology that can be overseen and audited by the Commission to ensure indifference and transparency. To reduce burden on all customers, however, any reductions in outstanding liabilities should first be pursued. To that end, prepayment should occur only after the Commission and utilities act to reduce outstanding stranded asset costs and/or sell the underlying attributes at maximum value. After reasonable efforts have been made to reduce portfolio costs, the net present value of any future net costs in the CCA's vintage would be used to calculate the prepayment amount.

The Joint Utilities concede that while the proposal would create certainty for both CCAs

⁵³⁹ Exh. AD-1 at IV.A.

and the Utilities⁵⁴⁰, they allege that it would put undue risk on bundled ratepayers. However, if prepayment creates certainty for the utilities that certainty will necessarily flow through to the ratepayers and any methodology adopted by the Commission would be transparent and fair to all. In addition, as discussed below our proposal does not shift costs unfairly to bundled customers. Prepayment of departing load obligations have been successfully used in California in similar circumstances. This approach has also been used outside of the State in support of retail competition. These examples – highlighted below and as provided in Mark Fulmer’s testimony for AREM/DACC⁵⁴¹ illustrate that it can be accomplished and has already been contemplated by the Commission. Together with the proposed Staggered Portfolio Auction⁵⁴² determining the prepayment amount, this proposal provides potential frameworks to facilitate prepayment transactions.

1. The Commission Has Previously Directed the Utilities to Permit California Publicly Owned Utilities to Prepay Departing Load Obligations

In 2007, Commission Resolution E-3999⁵⁴³ directed the IOUs to offer bilateral agreements to publicly owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff. The Commission rejected the utilities’ proposal to collect the full, undiscounted expected value of the CRS and other NBCs, plus an additional 2%, as unfair and inconsistent with Commission precedent. Instead, PG&E and SCE were directed to calculate a lump-sum payment based on the net present value of all future CRS and other NBCs.⁵⁴⁴

⁵⁴⁰ Exh. IOU-3 at 7B-33

⁵⁴¹ Exh. AD-1 at IV.C.

⁵⁴² See Section VI. B.

⁵⁴³ Resolution E-3999, available online at:

http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/62648.PDF.

⁵⁴⁴ The calculation of a net present value requires use of a discount rate. In this proceeding, the Commission used the IOU’s weighted cost of capital. Use of other discount rates may be appropriate depending on the type of obligation being paid off. For example, IOUs do not make any profits or return

Following this Resolution, PG&E and SCE entered into bilateral agreements with eight POU: Power and Water Resource Pooling Authority, Merced Irrigation District, Modesto Irrigation District, Turlock Irrigation District, and the Cities of Azusa, Rancho Cucamonga, Moreno Valley, and Victorville. Only three of the eight POU agreements have publicly available costs. Those costs range from a low of \$1.5 million under Modesto Irrigation District's agreement to a high of \$6.9 million under the Turlock Irrigation District's agreement in 2016. These LSEs each have over 100,000 customer accounts, and a load of 2,503 GWh and 2,000 GWh, respectively.⁵⁴⁵ In 2009, D.09-08-015⁵⁴⁶ expressly concluded that the PG&E/PWRPA agreement fully satisfied the departing load obligations of PWRPA's customers, and that PG&E had no right to seek further payment or pursue any claim against PWRPA's customers for charges under PG&E's departing load tariff. Thus, the Commission has previously approved an agreement that resolves past, present, and future nonbypassable charge obligations through payments of amounts that may differ from tariffed charges.

2. Commercial Customers Have Prepaid Bundled Service Obligations When Departing Utility Service in Neighboring States

Like California, Nevada has an RPS requirement (25% by 2025), additional renewable procurement required by legislation, and requires Commission approval for new generation. Recognizing these obligations, MGM resorts in Nevada left bundled service from Nevada Power Company in 2015 for a lump-sum payment of \$87 million and Switch, a data center company, departed utility service on payment of a \$27 million exit fee.

from the purchased power contracts, thus use of the weighted cost of capital may not be the appropriate metric. The ability to securitize these obligations would also affect the appropriate discount rate.

⁵⁴⁵ Source, 2016 EIA data. Available at: <https://www.eia.gov/electricity/data.php#sales>.

⁵⁴⁶ D.09-08-015, available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/105902.PDF.

MGM represented 4.86% of Nevada Power Company’s annual sales with 59 accounts at 19 different locations. In the buyout, the Public Utilities Commission of Nevada (PUCN) directed Nevada Power Company to perform production cost simulations to show the total costs with, and without, MGM. The Nevada Commission directed Nevada Power Company to include resources required by legislation procured while MGM was a customer, but to exclude future compliance obligations and “placeholder resources” not seeking specific approval. In addition, the PUCN directed NPC to include O&M savings resulting from reduced operation due to MGM’s departure. The net present value of all costs and savings were calculated based on NPC’s weighted average cost of capital.⁵⁴⁷

Switch was initially denied the ability to exit by the PUCN on the grounds that it violated the principle of indifference by failing to allocate a share of legislated energy policies into the exit-fee calculation. The PUCN later reconsidered this decision, and unanimously voted to grant Switch permission to depart service after paying a \$27 million exit fee.⁵⁴⁸

There are other examples of a departing corporate customer and the incumbent utility agreeing to lump-sum buyout terms. In 2016, Puget Sound Energy and Microsoft jointly filed an Advice Letter with the Washington Utilities and Transportation Commission recommending adoption of a tariff which would grant Microsoft the ability to procure its own generation and only take transmission and distribution service from Puget Sound Energy.⁵⁴⁹ In that case, the two entities agreed upon an exit-fee of \$23.9 million.

⁵⁴⁷ See Public Utility Commission of Nevada docket 15-05017 for MGM Application, testimony, and Staff response.

⁵⁴⁸ See Public Utility Commission of Nevada docket 16-09023 for documents related to the Switch Application.

⁵⁴⁹ See Washington Utilities and Transportation Commission docket UE-161123 for the Settlement Agreement and Order approving the Settlement.

While the Joint Utilities contest that these examples are not analogous to the situation at hand, we respectfully disagree. These western region examples, when viewed in light of a regional trend toward departing load, show how utility and consumer concerns have been successfully and adequately addressed in other instances. In addition, as AREM/DACC states in its testimony, each IOU already has in its New Municipal Departing Load tariff the option to have the PCIA and other departing load obligations paid as a negotiated lump sum.⁵⁵⁰

3. The Prepayment Calculation Could Rely on Values from the Staggered Portfolio Auction or as a Result of Bilateral Negotiation Subject to Commission Approval

After using a Reverse Auction for voluntary offers by sellers, securitization of a portion of the IOU portfolio, and performing a Staggered Portfolio Auction to reallocate resources and create a benchmark, prepayment could be used to address remaining resources and corresponding stranded-cost liabilities. A prepayment option preserves indifference and provides a path for LSEs to reduce volatility and protect their customers from rate shock. To calculate a prepayment value, two inputs must be determined: (1) the NPV of the future stream of costs for resources within the customer's vintage and, (2) the current market value of these resources. To calculate the NPV of future costs, the total amount of remaining obligations over the life of existing contracts should be aggregated by year and discounted at an appropriate rate. This will provide the total obligation – in today's dollars – on a per-customer basis.

The Staggered Portfolio Auction⁵⁵¹ could provide valuable information to determine the current market value; for the full host of attributes contained in various categories of resources with varying terms. Bundled ratepayers and other departing load customers sharing portfolio

⁵⁵⁰ Exh. AD-1 at IV.C 27-28.

⁵⁵¹ See Section VI.B.

obligations would be protected from an unreasonably low prepayment price through the use of a floor price in the SPA. Alternatively, direct bilateral negotiation, subject to Commission approval, as the utilities did for the eight POUs mentioned above, could identify the fair value of the remaining obligations. Once a fair value has been established, LSEs would have the option to prepay all or a portion of their vintaged obligation for various resource types using resource categories that match those used in the auction.

The Commission recently recognized prepayments as a method to preserve indifference in the context of Resource Adequacy. Resolution E-4907,⁵⁵² which stipulated terms for a transfer of RA from a utility to an LSE found that one of two conditions was necessary to preserve indifference: (1) a bilateral agreement between the utility and CCA, or (2) a Commission-calculated weighted average capacity cost which the CCA would have to pay. The Commission reasoned that that neither LSE would enter into an agreement that would harm its customers under the first scenario, and that the Commission could calculate the weighted average capacity cost of RA under the second.

4. Prepayment Would Not Shift Costs Among Bundled and Departing Load Customers

The Commission has an obligation to ensure that prepayment, like the calculation of the PCIA, does not shift costs among bundled and unbundled customers. There are two potential types of cost shift: (1) from the prepaying customers to bundled customers, *and* (2) from a prepaying customer to other departing load customers. The availability of actual, contemporaneous sales prices for similar products for a similar term could help calculate the prepayment amount and substantially reduce the risk of cost shifts. The prepayment terms

⁵⁵² Resolution E-4907, available online at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K016/210016662.PDF>

should mirror the payment obligations for PPAs and UOG resources included in the portfolio of resources for which the prepayment is being applied.

The Joint Utilities argue that prepayment is inherently at odds with the concept of indifference and would place departing load customers at risk.⁵⁵³ Yet every forecast that is made, whether in procurement or ratemaking, risks being too high or too low. A retroactive look at any commercial transaction several years after it has taken place – with access to information not available at the time of transaction – may lead one party to make a different choice if they could travel back in time. But as market participants inherently understand, all transactions are made based on the best available information at the time, not what parties have learned since. Every time an IOU enters into a long-term contract, its ratepayers are subject to the risk that the IOU may have made a commitment that might turn out to be ill-advised. In every long-term contract the IOU might also realize an unforeseen windfall benefit as it avoids future market spikes. In addition as AREM/DACC states in its testimony, allowing prepayment allows customers the flexibility to more easily switch among competitive retail sellers while also foreclosing on the opportunity for refunds, thereby providing certainty for both parties.⁵⁵⁴

B. PCIA Caps and Sunsetting of Cost Responsibility Merit Consideration

1. The Commission Should Permit Parties to Request Rate Caps in Forecast ERRA Proceedings If Circumstances Warrant

CalCCA members place a high value on predictability and stability in the PCIA rate from year-to-year. The current annual fluctuation of PCIA charges makes planning efforts difficult, in particular efforts to pursue clean resource development objectives. One stabilizing tool that can be used and has been utilized by the Commission in the past is a rate cap. A cap provides

⁵⁵³ Exh. IOU-3 at 7-13.

⁵⁵⁴ Exh. AD-1 at 5:3-4.

assurances to both the CCA and its customers that costs outside of the CCA’s control – the PCIA rate – will not result in rate shock or otherwise interfere with procurement planning.

The Commission has adopted rate caps both in the context of rate cases and stranded cost responsibility. In SCE’s GRC Phase II Rate Case,⁵⁵⁵ the Commission adopted a settlement capping rate increases to 3% for distribution revenues and 2% for generation revenues in order to avoid rate shock and to transition more moderately to cost-of-service rates.⁵⁵⁶ A fixed rate cap of 2.7¢/kWh on the DA CRS was also adopted by the Commission in response to concerns that the level of CRS imposed on DA risked making DA uneconomic.⁵⁵⁷ In both cases, costs above and below the cap were netted in a balancing account to ensure full cost recovery over time.⁵⁵⁸

CalCCA sees the potential value in a rate cap, depending upon the evolution of the PCIA rate but does not propose a cap at this time. While other parties in this proceeding, including TURN⁵⁵⁹ and AREM/DACC⁵⁶⁰ do propose the adoption of a cap on year-to-year changes in PCIA charges here, if the Commission declines to do so. CalCCA requests, that the Commission establish the opportunity for parties to evaluate the need for and to propose a rate cap in each annual Forecast ERRA. The Joint Utilities argue that the ERRA is not the appropriate forum,⁵⁶¹ but instead seemingly concede that any cap should be addressed in this proceeding via a Petition for Modification.⁵⁶² This objection ignores the fact that the Commission can modify any prior

⁵⁵⁵ A.14-06-014.

⁵⁵⁶ D.16-03-030 at 11. The Decision acknowledges that “Capping...of allocated revenues to rate groups...promote[s] rate stability while achieving movement towards cost-based rate levels.”

⁵⁵⁷ D.02-11-022, Ordering Paragraph 19 at 109.

⁵⁵⁸ *Id.* at 24-27.

⁵⁵⁹ Exh. TURN-1 at 11-14

⁵⁶⁰ Exh. AD-1 at 5:5-15

⁵⁶¹ Exh. IOU-3 at 5-12:23-33.

⁵⁶² *Id.* at 5-13:1-3

decision in this rulemaking, permitting parties to request caps in the future if circumstances support their adoption.

2. The Commission Should Consider Establishing a Fixed Sunset Date or Trigger Event for Sunset of the PCIA

Non-utility LSEs share frustration with the continuing presence of stranded procurement costs and the related surcharges. Some ESPs have been dealing with stranded procurement costs – whether the CTC, DWR Power Charge or the PCIA – for two decades. Yet there is no clear end in sight. AB 117 makes clear, for example, that a CCA customer will bear cost responsibility for “net unavoidable costs” of purchase contracts until these contracts expire or are terminated; many of these contracts have terms of up to 25 years or longer.⁵⁶³ Seemingly every new piece of legislation, most recently SB 350,⁵⁶⁴ offers some version of stranded cost responsibility. While the underlying motivation for these provisions is understood – preventing cost shifts – the dynamics surrounding the stranded cost problem must be addressed for stranded costs to fully sunset.

The Commission should make a finding in this case regarding the establishment of a defined sunset date for these stranded costs. Constraints on stranded cost recovery, such as the limitation on CTC recovery pursuant to AB 1890, reflect a legitimate viewpoint that transitions should not be open-ended but should be subject to defined limits around the time, scope and magnitude of above-market cost recovery. A fixed time limit on departing load cost recovery, to the extent permitted by law and consistent with other state policy goals, would provide greater certainty and flexibility to CCAs in building the optimal portfolio to meet their customers’ needs. Consistent with the other arguments CalCCA has made herein, certainty in the market helps

⁵⁶³ Cal. Pub. Util. Code §366.2.

⁵⁶⁴ Cal. Pub. Util. Code §740.12(c)

entities plan and pursue resource goals. A defined sunset would go a long way to providing this certainty.

C. The Commission Should Require the Utilities to Formalize the Approach Used in this Rulemaking for Long-Term PCIA Forecasting in ERRA Proceedings

A key objective for CalCCA in this proceeding is the implementation of a reasonable, transparent, and repeatable process for forecasting long-term PCIA rates for use among the various parties. A realistic long-term PCIA rate forecast would be supportive of CCAs' overall business planning, procurement decision making, portfolio risk management, ratesetting and other related operational functions. CalCCA believes there is a workable path for the Commission, building upon the insights gained and work completed in this proceeding, to define a process of maintaining and continually refreshing a long-term forecast of PCIA rates.

Under the CCA proposal, the utilities would leverage the work done in this case to build and maintain a model capable of presenting reasonable projections of PCIA eligible portfolio cost value metrics. The CCA proposal would:

- Formalize the approach embodied in the "ALJ Data Matrix" to project long-term (10-years or longer) projections of the Generation Volumes (in GWH) and Total Cost (in \$) of all resources in their PCIA-Eligible portfolios.
- Require the utilities to provide annual updates of these long-term projections as part of their annual ERRA Forecast filings.
- Provide a section of the model for parties to input forward market price curves of their own choosing, upon which to calculate the Market Value and Net Costs (Total Costs in excess of Market Value).

The availability of this information will allow parties' reviewing representatives to calculate long-term projections of the Indifference Amount and Indifference Rate (differentiated by rate class and vintage). The information should be made available to parties under the Modified NDA developed in this proceeding to cover access and use of this material.

An alternative should be made available for parties who are unable to designate a reviewing representative under the Modified Non-Disclosure Agreement (MNDA). These parties should be permitted to provide a forward price curve to the utility and have the utility generate the long-term PCIA forecast for their vintage.

CalCCA believes that formalizing this approach, building on work that has been proven workable and highly valuable in this proceeding, provides a reasonable opportunity for all parties to gain the benefit of long-term PCIA forecasting while minimizing the burden on the utilities. The Joint Utilities argue that such an approach is an unreasonable and unjustified burden and not supported by law and instead suggests basing the forecasting methodology on the specific data required to develop a long-term forecast under the particular cost allocation method the Commission ultimately adopts in this proceeding. The Joint Utilities object to the use of the MNDA for providing the information proposed by CalCCA or a limited waiver of the Commission's confidentiality rule.⁵⁶⁵ However, Guiding Principle 1(a)⁵⁶⁶ states that the PCIA methodology "should be transparent and verifiable, including the most open and easily accessible treatment of input data, while maintaining confidentiality of information that should remain confidential." The utilization of the MNDA (or another form of NDA agreed upon by the parties) strikes a sufficient middle ground whereby the interested parties get the information they need while maintain confidentiality of that information as it relates to the public at large.

The Joint Utilities also allege that the CalCCA proposal conflicts with the Guiding Principle that LSEs should be responsible for power procurement activities performed on behalf of their customers, but does not fully explain how the CalCCA proposal violates Guiding

⁵⁶⁵ Exh. IOU-3 at 6:4-12.

⁵⁶⁶ Scoping Memo at 13-14

Principle 1(f).⁵⁶⁷ This guiding principle provides that “Any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load: should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as required by law.”⁵⁶⁸ CalCCA believes that the proposal does not violate the guiding principle, but instead creates a means for LSEs to manage portfolios with more certainty. The Joint Utilities cannot reasonably argue that CCAs should pay as much as 85% of PCIA-eligible costs absent the reasonable transparency requested here.

D. The Commission Should Require the Joint Utilities to Separately Identify Uneconomic Costs as a Line Item on Bundled Customers’ Bills

The PCIA rate reflects the uneconomic costs of utility procurement and is charged to bundled, CCA and DA customers. Even though all customers, including the utility’s bundled customers, pay for the uneconomic costs reflected in the PCIA, the charge is not separately identified on the Energy Statements provided to bundled customers. In contrast, the PCIA rate is separately identified on the Energy Statement provided by PG&E to CCA or DA customers, allowing a distinction between the CCA or DA supplier’s costs and the customer’s share of the utility’s uneconomic costs.

The current utility bill presentation masks the fact that all customers are shouldering the burden of the utility’s uneconomic costs. Today, a customer who performed a side-by-side comparison of billing formats would observe that the CCA bill includes a rate that is not present on the bundled service bill. Without explanation, customers might erroneously conclude that CCA customers are required to pay additional costs not included in bundled service. This need for greater transparency is a acknowledge by the Joint Utilities in their rebuttal testimony

⁵⁶⁷ Exh. IOU-3 at 6:11-12.

⁵⁶⁸ Scoping Memo at 14.

The Commission should direct the utilities to modify this practice, requiring separate identification, using the same terminology, of the component of all customers' rates that recovers uneconomic costs. Applying the charge similarly on all bills prevents this charge from becoming a competitive issue when comparing alternatives and makes clear that all customers – bundled, CCA and DA customers – are sharing this cost responsibility and allows all customers to compare their options equally. Operationally, this will also reduce confusion in a scenario in which customers can move back and forth between bundled and un-bundled service.

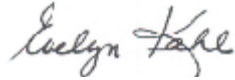
Recognizing that the uneconomic cost portion of the rate is not an “indifference adjustment” when applied to a bundled customer, the PCIA rate and the bundled customer analog should be labeled more descriptively. We recommend labeling the charge the “Electricity Provider Transition Charge.” The Joint Utilities agree that transparency is needed stating in their rebuttal testimony that “greater transparency can and should be achieved through modifications to both utility tariffs and customer bill formats.”⁵⁶⁹ However, they argue that it could take considerable time to change the Utilities billing systems. Therefore the Commission should order the Joint Utilities to set forward on the path towards revising bill formats for more clarity as described above and set forth a process for achieving such a goal. The workshop process proposed by the Joint Utilities in 2019 could be used to accomplish this goal; however the Commission should set a deadline for implementation.

⁵⁶⁹ Exh. Joint Utilities Rebuttal Testimony 1-14:25-27.

XII. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission adopt the proposals set forth herein.

Respectfully submitted,

A handwritten signature in cursive script that reads "Evelyn Kahl". The signature is written in black ink and is positioned to the left of a vertical line.

Evelyn Kahl
Counsel to the
California Community Choice Association

June 1, 2018



Apple Valley Choice Energy

Clean Power Alliance

CleanPowerSF

Desert Community Energy

East Bay Community Energy
Authority

Lancaster Choice Energy

MCE

Monterey Bay Community
Power Authority

Peninsula Clean Energy

Pioneer Community Energy

PRIME

Redwood Coast Energy
Authority

San Jose Clean Energy

Silicon Valley Clean Energy
Authority

Sonoma Clean Power

Valley Clean Energy Alliance

June 4, 2018
CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th floor
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Subject: Protest of PG&E Advice Letter 3976-G/5292-E Proposing Revisions to 15-Day Notice and 48-Hour Notice on Customer Energy Statements to Include Payment Details

Dear Tariff Unit and Mr. Randolph:

The California Community Choice Association (“CalCCA”) on behalf of its members, particularly the Community Choice Aggregators (“CCAs”) within Pacific Gas and Electric Company’s (“PG&E”) service area, provides this protest of Advice Letter 3976-G/5292-E (“Advice Letter”) pursuant to General Order (“G.O.”) 96-B, Energy Industry Rule 7.4.

CalCCA respectfully requests the California Public Utilities Commission (“Commission”) approve the advice letter with modifications as described in this protest. First, the Advice Letter violates G.O. 96-B because it raises significant policy questions about PG&E’s role as the exclusive billing agent for CCAs. Second, PG&E’s proposed revisions to the 15-Day and 48-Hour notices neglect to advise customers of the debt collection that may result if a customer fails to pay a Service Provider’s outstanding balances (*i.e.* an outstanding balance due to a CCA). This omission risks customers being unaware of the actual consequences resulting from non-payment of the total past due amount. As such, CalCCA recommends adjustments to PG&E’s proposed revisions that would (1) obviate the risk of increased customer confusion resulting in debt collection costs for CCA customers and (2) avoid undermining PG&E’s responsibility as the exclusive billing agent for CCAs.

I. PG&E’s Proposed Notice Revisions Violate G.O. 96-B

G.O. 96-B, Rule 5.1 provides that “Matters appropriate to Advice Letters . . . are expected neither to be controversial nor to raise important policy questions.” PG&E’s advice letter should be modified to avoid violating G.O. 96-B because it raises important policy questions related to PG&E’s statutory role as the exclusive billing agent for CCAs.¹ Specifically, PG&E’s Advice Letter fails to adequately notify customers about consequences of carrying past due amount.

¹ Pub. Util. Code Sec. 366.2(c)(9).

PG&E proposes the following revisions to both the on-bill and standalone notices (bold emphasis added):

*Your bill includes a past due balance of \$XXX.XX. **Service Provider past due charges are \$aaa.aa. PG&E past due charges are \$bbb.bb.** To avoid disconnection of your utility service, please pay **\$bbb.bb** on or before mm/dd/yyyy. For assistance or to make a payment, please call customer service at 1-800-743-5000*

PG&E's language emphasizes the importance of paying PG&E's past due charges to avoid service disconnection. Yet, PG&E fails to articulate the consequences for failure to pay Service Provider past due charges including debt collection processes. Therefore, PG&E's Advice Letter creates the hazard that customers will be unaware of the actual debts they are responsible to pay and future consequences of non-payment.

As the exclusive billing agent for CCAs, PG&E is uniquely positioned to advise customers of their outstanding debt and thereby prevent costly debt collection activities. PG&E's failure to adequately describe the consequences of non-payment of the entire past due charges implicates a significant policy issue of PG&E's role to conduct billing operations for CCAs. On this basis, PG&E's Advice Letter is impermissible under G.O 96-B, and should be modified as described below before being approved.

II. CalCCA Recommends G.O. 96-B Compliant Notice Revisions That State the Consequences of Not Paying Both Service Provider Past Due Charges and PG&E Past Due Charges

PG&E's Advice Letter proposes useful changes to customer energy statements and notice forms. Previously the notice did not make any reference to Service Provider charges. While the proposed revisions advise customers of the past due amounts for both PG&E and Service Providers, the revisions only warn the customer that payment of the PG&E charges will avoid disconnection. The revisions do not advise customers that failure to pay Service Provider past due charges could result in debt collection activities. CalCCA urges the Commission to reject the Advice Letter as proposed and instead adopt minor revisions to bring the Advice Letter into compliance with G.O. 96-B. CalCCA's revisions improve upon PG&E's proposed language because they communicate (1) the past due amounts that remain outstanding for a customer's account, and (2) the consequences of failing to pay the full outstanding balance. CalCCA proposes the following adjustments to the 15-Day and 48-Hour notice revisions proposed in PG&E's Advice Letter (emphasis added):

*Your bill includes a past due balance total of \$XXX.XX. **To avoid disconnection of your utility service, please pay a minimum of \$bbb.bb on or before mm/dd/yyyy. Failure to pay the full past due balance of \$XXX.XX may result in debt collection efforts.** For assistance or to make a payment, please call customer service at 1-800-743-5000.*

III. Conclusion

CalCCA thanks the Commission for its consideration of this protest. For the reasons set forth above, the Commission should approve the Advice Letter with the modifications proposed in this protest.

Respectfully,

/s/ Beth Vaughan

Beth Vaughan

Executive Director, CalCCA

/s/ Michael Callahan

Michael Callahan

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On behalf of the CalCCA



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

Order Instituting Rulemaking to Continue)	
Implementation and Administration, and)	
Consider Further Development of,)	Rulemaking 15-02-020
California Renewables Portfolio Standard)	(Filed February 26, 2015)
Program.)	

**INFORMAL COMMENTS OF THE CCA PARTIES
ON PROPOSED MODIFICATIONS TO
THE ANNUAL RPS COMPLIANCE REPORT SPREADSHEET**

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Counsel for the City of Lancaster

And on behalf of Marin Clean Energy,
Peninsula Clean Energy Authority,
Redwood Coast Energy Authority, Silicon
Valley Clean Energy Authority, and
Sonoma Clean Power Authority
(collectively, "CCA Parties")

Dated: June 5, 2018

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

Order Instituting Rulemaking to Continue)	
Implementation and Administration, and)	
Consider Further Development of,)	Rulemaking 15-02-020
California Renewables Portfolio Standard)	(Filed February 26, 2015)
Program.)	

**INFORMAL COMMENTS OF THE CCA PARTIES
ON PROPOSED MODIFICATIONS TO
THE ANNUAL RPS COMPLIANCE REPORT SPREADSHEET**

Pursuant to the May 17, 2018 Energy Division email requesting informal comments on the Draft Renewables Portfolio Standard (“RPS”) Compliance Report Template, the City of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”), Peninsula Clean Energy Authority (“PCE”), Redwood Coast Energy Authority (“RCEA”), Sonoma Clean Power Authority (“SCP”), and Silicon Valley Clean Energy Authority (“SVCE”) (collectively, “CCA Parties”) respectfully submits these comments.¹ The following comments recommend improvements to, as well as identify problems with, the current draft template.

1. Functionality Improvements

A. PDF Conversion

One major problem that many compliance entities face is that the entire workbook cannot be easily converted into a single PDF. Instead, compliance entities must convert each individual tab into a separate PDF. This is not only burdensome, but also results in filings that may exceed the size limitations for many of the email systems used by individuals on the service list.

Compliance entities must then go through the process of reduce the file size to ensure service can

¹ Pursuant to Rule 1.8(d) of the California Public Utilities Commission’s (“Commission”) Rules of Practice and Procedure, MCE, PCE, RCEA SVCE and SCP have given counsel for the City of Lancaster permission to sign these comments on their behalf.

be completed. Energy Division Staff should work to reduce these burdens by ensuring that the entire workbook easily converts to a PDF.

B. Adding Rows

On several of the template tabs, there is no ability to insert additional sheet rows. For example, all of the 36 Month Retirement Sheets prevent the user from adding sheet rows, even though each of these sheets only comes with 24 rows. Energy Division should ensure that this functionality is unlocked on all forms where it is possible that a compliance entity will need to add more rows.

2. Alignment with other Reporting Requirements

Energy Division should work to better align the reporting requirements in the template with other similar reporting requirements at both the California Public Utilities Commission (“Commission”) and California Energy Commission. To the extent that the same procurement is being reported multiple times in different formats, it creates unnecessary administrative burdens. The RPS, Power Source Disclosure (“PSD”), Integrated Resource Plan (“IRP”), Integrated Energy Policy Report (“IEPR”) Supply Forms, and other similar reports should be consistent to the greatest extent possible. Currently, the PSD and IEPR Supply forms are structured on a vintage-basis, with the reporting based on the year of generation. Further, under the Western Renewable Energy Generation Information System (“WREGIS”) accounting system, users generally retire renewable energy credits (“RECs”) into the subaccount associated with the year of generation (*e.g.*, 2017 CA RPS RTSL). In contrast to these vintaged-based reporting requirements, the RPS template is focused on the underlying contracts.

3. Contract Structures

Many contracts for renewable generation identify a list of potential RPS-eligible resources that may supply power over the term of the contract. Under these contracts, the seller has the authority to choose from any of the resources identified on the list. This list may be fixed, or the contract may permit the seller to add more resources to the list of eligible resources under the contract. Over the term of a contract, a buyer could actually purchase generation from a significant number of different sources.

The draft template does not easily accommodate these types of contracts because the template only allows one resource to be selected for each contract. This means that compliance entities must re-enter the same contract information in on multiple lines to accurately reflect these requirements. Energy Division should consider a functionality where a single contract can have multiple resources associated with it.

4. Long-Term Contracting Requirements

There appear to be problems with the formulas on the “Procurement Detail” Sheet, dealing with long term contracting requirements. When entering test data into the template for the fourth and fifth Compliance Periods, Rows 19 and 22 show significantly higher long term contracting requirements than the total procurement quantity requirement applicable during the relevant period. These problems have hindered the ability to determine whether the long-term contracting requirement has been properly implemented in this draft.

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5. Conclusion

The CCA Parties appreciate the opportunity to provide these informal comments.

June 5, 2018,

Respectfully submitted,

/s/ Justin Wynne

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And on behalf of Marin Clean Energy,
Peninsula Clean Energy Authority,
Redwood Coast Energy Authority, Silicon
Valley Clean Energy Authority, and Sonoma
Clean Power Authority

Diversification is Not Deregulation

CCAs have procurement autonomy, which diversifies the retail energy market and stimulates competition and innovation in electricity generation. CCAs are also robustly regulated by:

California Public Utilities Commission (CPUC)

- » Statewide standard compliance: renewable portfolio standards (RPS), resource adequacy (RA), storage requirements, integrated resource planning (IRP)

Western Renewable Energy Generation Information System (WREGIS)

- » Renewable energy credits retirement reporting

California Independent System Operator (CAISO)

- » Flexible capacity needs reporting

California Energy Commission (CEC)

- » Integrated energy policy report demand forecasts and resource plans

Boards of Local Government Elected Officials:

- » CCAs hold board meetings open to the public with notice requirements under the **Brown Act**. The meetings include discussion and decisions on management, policy, and procurement, such as:
 - » Power purchase agreements (PPAs), vendor contracts, and public work activities.
 - » Key planning documents such as MCE's integrated resources plan (IRP).
- » Disclose non-confidential documents at the request of a member of the public as required under the **California Public Records Act**.
- » Are accountable to the community and serve over 80% of the customers in their service areas.

Disclaimer: This is intended to serve as a sample of CCA compliance obligations.

CCAs Drive State Goals

1) DECARBONIZATION

MCE has always exceeded the state's minimum requirement for renewable power and currently provides 50-100% renewable power and 80-100% greenhouse gas-free power to all customers.

2) RELIABILITY

MCE has invested more than \$1.6 billion to build 813 megawatts of new renewable projects in California.

3) AFFORDABILITY

MCE maintains affordable rates, often lower than PG&E even when counting utility exit fees.

The Enduring Role of the IOUs

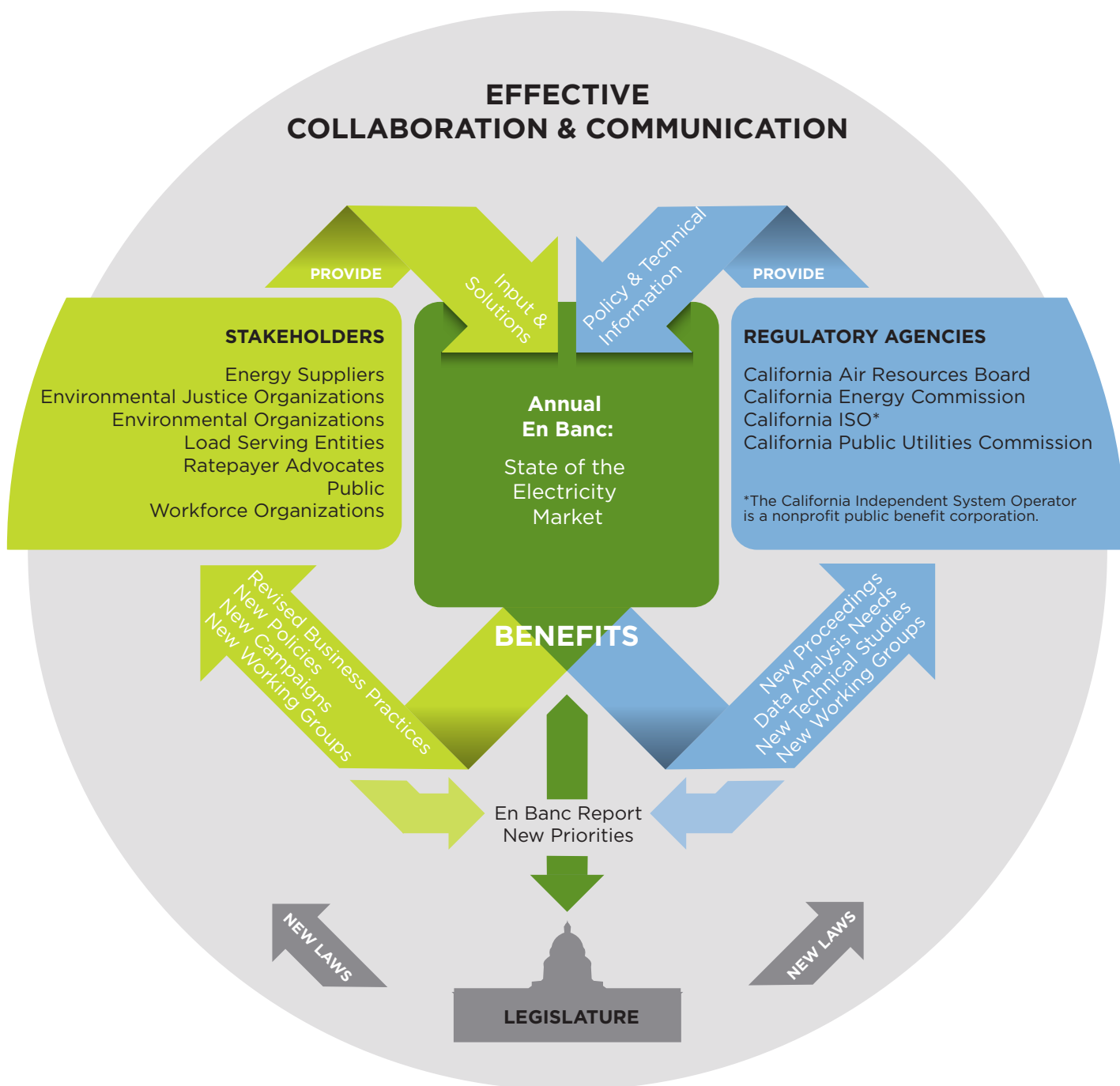
The CPUC estimates that non-utility providers, including CCAs, will provide 85% of electricity generation by the mid-2020s. However, the utilities will likely continue to:

- » Operate the transmission and distribution (T&D) system financially supported by all ratepayers, including CCA customers
- » Provide data and appropriate incentives to the market to help support grid operations
- » Collaborate with first responders to lead emergency response efforts, an obligation for which the utilities collect funds from all ratepayers, including CCA customers.

The Evolving Role of the CPUC

Historically, the CPUC developed around regulating a monopoly, profit-driven utility industry. CCAs, however, make procurement decisions guided by statewide standards and considering local priorities and long-term stability. The state can rely on statewide standards and does not need a centralized procurement model to ensure state goals are achieved. MCE proposes that the CPUC focus its role in the transforming energy market on the following:

- » Continuing to set and enforce key standards
- » Informing customers about price details and energy choices
- » Safeguarding against anti-competitive practices
- » Cultivating innovation
- » Advancing social equity and environmental justice
- » Facilitating collaborative dialogue between regulators, stakeholders, and the legislature through an annual en banc on the State of the Electricity Market



DO YOU HAVE QUESTIONS?

Michael Callahan
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Local Communities Call for Collaboration:
Reliability, Climate Change, and Affordability
Through a Time of Transition

MCE COMMENTS ON DRAFT GREEN BOOK

6.11.2018

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I. Introduction

Marin Clean Energy (MCE), a Community Choice Aggregator (CCA), supports the monumental strides California has made in transforming the electricity sector to provide reliable and clean service while keeping rates affordable. Many actors, including the legislature, regulators, and other stakeholders, have worked in concert to achieve this progress.

CCAs play a vital role in this transformation by offering an affordable choice to customers, exceeding state requirements for renewable electricity, and engaging in dialogue about issues that affect the electricity market. The CCA model complements the regulated utility model by introducing a diversity of approaches that incorporate local considerations and accountability. This diversity should be embraced in an expanded dialogue to solve issues facing the state's electricity market.

II. Diversification is Not Deregulation

A local government electricity provider, bound by government regulations without a profit motive, can provide customers with an alternative to a profit-driven monopoly corporation. Deregulation is antithetical to the CCA model, which is subject to various regulations and policy directives established by federal, state, and local governments. Since its founding, MCE has aimed to provide workforce benefits and cleaner electricity products to its local communities. MCE's operations demonstrate that incorporating local needs introduces new goals and mandates that are supplementary to California's consumer protection and decarbonization mandates.

The CCA enabling statute was passed after PG&E filed for bankruptcy during the energy crisis, as an alternative model run by local government on behalf of entire communities.¹ CCAs are regulated first and foremost by their local governing board, which consist of elected officials that are held accountable to their constituents. Many aspects of CCAs are also regulated by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Air Resources Board (CARB). As Load Serving Entities (LSEs), CCAs schedule power into the California Independent System Operator (CAISO) and are subject to the same key market rules and regulations as the utilities.²

Today, CCAs provide the following benefits:

- » competitive rates, even when including utility exit fees;
- » cleaner electricity than utilities;
- » the ability to identify and respond to local needs;³
- » reliable service through local governance and decision-making, within the bounds of statewide requirements; and
- » healthy pressure on the utilities through market competition to decrease their costs.

MCE appreciates the efforts of the CPUC in preparing the draft white paper and facilitating a dialogue around customer choice, and looks forward to engaging in dialogue with decision makers and stakeholders. MCE shares the same goals expressed in the white paper that California's electricity market must ensure affordability, decarbonization, and reliability. However, the high-level discussion in the draft does not provide an accurate lens for building towards those goals. Instead, the draft white paper provides a problem statement that assumes customer choice places those goals in jeopardy.

The draft white paper claims that California is "deregulating" the electricity market and calls for a plan in response.⁴ As mentioned above, CCAs are regulated in many of the same ways that utilities are and have additional obligations

¹ Richard Halstead, *Legislation that made Marin Clean Energy possible emerged from chaos of deregulation*, Marin Independent Journal, May 5, 2010. Available at <http://www.marinij.com/article/zz/20100505/NEWS/100509739>.

² Appendix I lists a sample of the compliance requirements required of CCAs.

³ See *generally* Comments on CPUC Customer Choice Workshop, Lorenzo Kristov, Ph.D., October 31, 2017.

⁴ Draft Green Book, CPUC, May 2018, at p. iii.

for transparency, accountability, and local priorities. The CPUC may be concerned that oversight is shifting to local elected officials as customers depart utility service for CCA service. **This shift is not deregulation. Instead it is diversification and decentralization, which strengthens the electricity market.** The formation of publicly owned utilities (POUs) and CCAs has demonstrated that local governments can provide high levels of service and low electricity rates. California's electricity market does not require a few large entities to meet the goals of affordability, decarbonization, and reliability.

A. Diversification: Driving State Goals

California is rapidly achieving its renewable goals thanks to early investments by utilities and more recently from substantial contributions by CCAs. The utilities have largely met the state requirements for renewable electricity through long-term contracts. As customers depart utilities for CCA service, the utilities' load decreases, and those long-term renewable contracts have increasingly become larger portions of their portfolios. This means the utilities may not need to purchase more renewable electricity unless demand increases (e.g. from growing electric vehicle use or electrification in buildings). Meanwhile CCAs are purchasing renewable electricity to exceed the state requirements for those same customers that departed utility service. **This procurement by CCAs is the leading driver for new steel-in-the-ground, renewable development in California.** The diversity in procurement approaches, and in particular the actions of CCAs, is driving California toward cleaner electricity.

B. Essential Responsibilities: Regulating Monopoly Utilities and Promoting Collaboration

As customers depart utility service for CCA service, some oversight shifts from the CPUC to local elected officials. However, the CPUC still serves an essential role in protecting all customers, including CCA customers who have departed utility generation service yet still receive transmission and distribution (T&D) from the utilities. The CPUC should continue to ensure that for-profit monopoly utilities charge just and reasonable rates in the provision of safe, affordable, and reliable service. As the draft white paper states, the utilities will retain monopoly status for T&D service.⁵ State law also grants the utilities a monopoly in meter data management and billing service to customers, regardless of the presence of a CCA. The CPUC will continue to regulate the actions of monopoly utilities to ensure California's electricity market is a level playing field and that all customers are protected.

There is a growing need to address issues through robust communication and collaboration between all entities engaging with California's electricity sector. CCAs engage with the Legislature, CPUC, CEC, CAISO, and CARB in their efforts to address statewide issues. CCAs embrace new solutions to problems, such as the need for more flexible capacity and the economic challenges facing existing generation resources. CCAs agree that new resources must be used to achieve reliability while also achieving state climate goals. **Customer choice should not be made a scapegoat for these issues but should be embraced as a partner in solving them.** MCE is optimistic that the customer choice project will lead to a more comprehensive, collaborative, and durable dialogue.

III. The Enduring Role of the IOUs

CCAs were authorized to provide customers a choice for their electricity generation service. This empowers customers and creates incentives for providers to meet customer needs at stable and competitive rates. Utilities may have a continued role in providing electricity generation service to customers to preserve the benefits offered by customer choice.

As described in the draft white paper, the utilities must continue to be responsible for the safe and reliable operation of the T&D system.⁶ The utilities will continue to finance large T&D investments through T&D rates as they do today.

⁵ Draft Green Book at p. 25.

⁶ Draft Green Book at p. 25.

The white paper mentions a concern that utility revenues are declining as a result of CCA load departure, and this may impact utility T&D operations.⁷ However, CCA formation has no impact on revenue from the profit-generating T&D side of the utility business,⁸ as CCA customers continue to pay the utilities for T&D service. Since utilities will continue their monopoly role in operating the T&D system, there are no legally permitted impacts to the utility business model related to declining revenues.

Utilities should continue work to provide more data and appropriate incentives to private entities and CCAs to help support grid operations. These efforts are underway in the Commission’s Distributed Resources Planning (DRP) proceeding⁹ and Integrated Distributed Energy Resources (IDER) proceeding.¹⁰ These efforts are critical to ensure that the T&D functions of the grid are relatively low-cost. As CCAs and private entities are adding resources to the grid, such as storage or energy efficiency, the planning should be guided by grid needs and benefits. The data and incentives from the utilities should help channel this activity to minimize the need for investment in the T&D grid.

The white paper raises the issue of safety controls and protocols in times of crisis, claiming they are more difficult to fund and coordinate with greater customer choice.¹¹ The utilities, in cooperation with first responders, typically lead emergency response efforts. Utilities should continue to serve this role as the T&D operator and collect funding for it through T&D rates. CCAs are willing partners in sharing critical information with customers, such as the availability of emergency relief services. In times of market fluctuations, such as a hot day with little wind resulting in increased air conditioning use and decreased wind generation, CCAs and utilities alike respond in real time to market signals provided by the CAISO. All LSEs have a shared interest in planning to manage and avoid these costly events. CCAs welcome increased coordination with utilities and the state to respond to times of crisis.

IV. CCAs Complement a Successful Retail Market Structure

CCAs are an important part of a customer-centric electricity market. CCAs are driven by their mission to serve local communities, not by a profit motive. This is a primary reason CCAs have exceeded state customer protection and environmental goals, while maintaining competitive rates for their customers. Due to their local nature, CCAs are nimble and focused on responsiveness to their communities. These advantages have allowed MCE and other CCAs to support and exceed the state goals highlighted in the draft white paper:

1) DECARBONIZATION

MCE has always exceeded the state’s minimum requirement for renewable power and currently provides 50-100% renewable power and 80-100% greenhouse gas-free power to all customers.

2) RELIABILITY

MCE has invested more than \$1.6 billion to build 813 megawatts of new renewable projects in California.¹²

3) AFFORDABILITY

MCE maintains affordable rates, often lower than PG&E even when counting utility exit fees.

7 Draft Green Book at p. 19.

8 Utilities are not authorized to earn a profit on their generation service.

9 Rulemaking 14-08-013.

10 Rulemaking 14-10-003.

11 Draft Green Book at p. 19.

12 See Appendix II.

MCE supports strong oversight of statewide standards, including the renewable portfolio standard (RPS), energy storage mandate, and resource adequacy (RA). Statewide standards should be strictly enforced and change over time to accommodate state goals. MCE also supports the exploration of new state standards and the statewide enforcement of existing standards, including collaborating on the development of new standards for successful CCA implementation plans.

A. CCAs Bring Transparency to the Market

CCAs introduce new transparency to California's electricity market as local government entities. Local governments are subject to open meetings with notice requirements under the Brown Act. MCE extends invitations to its board meetings to all interested individuals, including regulatory decision makers. These meetings include discussions and decisions on management, policy, and procurement, such as:

- » Power purchase agreements (PPAs), vendor contracts, and public works activities.
- » Key planning documents such as MCE's integrated resources plan and energy efficiency business plan.
- » New employee positions, staff compensation, and agency policies.

In addition to the Brown Act, CCAs comply with the Public Records Act and respond to requests in a timely manner.

These regulations, which are applicable to CCAs but not private utilities, have led to more information available to the market, policy makers, and the public.

B. CCAs Serve the Vast Majority of Eligible Customers

CCAs have strong incentives to provide excellent service as a default provider. State law makes CCAs the default provider in their service areas by establishing an opt-out model.¹³ Before customer choice was introduced, the utility was the default provider. Local governments affirmatively take on that role, similar to their traditional roles providing water or sewer services, when forming or joining a CCA. But unlike water or sewer services, customers can opt-out of the CCA and return to utility electricity service. CCAs strive to serve customers with excellence, resulting in retaining over 80% of the customers in their service areas.

As identified in the draft white paper, a discussion is needed to better define the provider of last resort (POLR) for electricity service.¹⁴ Under current rules, the utility would serve customers in the unlikely event a CCA ceases operations.¹⁵ The costs incurred to provide service to those returning customers are borne by the CCA.¹⁶ It may be appropriate for an alternative approach given that CCAs provide service to 80% or more of the customers in their service area. CCAs could potentially take on this role. It is worth noting that even the utilities were not able to fully serve this role during the energy crisis as the state of California through the Department of Water Resources (DWR) had to step in to purchase power. The auction and contracting models explored in white paper should be further vetted as to whether they could be applied to California. MCE looks forward to making progress in this area to ensure that risks to California ratepayers are appropriately managed.¹⁷

CCAs complement a successful retail market structure through choice, accountability, and transparency. CCAs provide customers a choice and utilities a competitive pressure to perform well. CCAs are mission-driven local government entities with local community control and accountability. CCAs serve customers transparently and have strong incentives to provide excellent service. MCE supports strong and meaningful regulation that underpins the CCA model and embraces an exploration of the most appropriate entity to serve as the POLR. MCE looks forward to collaborating with the state to deliver high quality electricity service in a diverse and healthy retail market.

¹³ California Public Utilities Code 366.2.

¹⁴ Draft Green Book at p. 19.

¹⁵ Pacific Gas and Electric Company Rule 23 Tariff, Sections S, T; Southern California Edison Company Rule 23 Tariff, Sections S, T; and San Diego Gas and Electric Company Rule 27 Tariff, Sections S, T.

¹⁶ California Public Utilities Code 394.25(e); Decision 18-05-022.

¹⁷ This may be added to the scope of the CCA Rulemaking 03-10-003.

V. The Evolving Role of the Regulators

California currently relies on robust coordination between statewide energy agencies to achieve its goals. As the electricity market decentralizes, more coordination is needed with other governmental and regulatory agencies, including CCAs. As previously mentioned, MCE extends a standing invitation to anyone interested in attending its board meetings.¹⁸

Decentralization requires regulatory innovations. The CPUC has been developed around regulating a handful of for-profit utilities, and needs to expand its capacity to collaborate with other governmental entities, such as CCAs and other statewide agencies. For example, consistency in the greenhouse gas (GHG) accounting methodologies among the CARB, CEC, and CPUC is a critical issue that requires robust collaboration to provide a stable and consistent regulatory environment for the electricity market.

A. Setting and Enforcing Standards, Not Centralizing Procurement Decisions

The CPUC should continue to enforce statewide standards. While the governing boards of CCAs have the statutory responsibility to make procurement decisions, CCAs are also bound by statewide standards. ***The draft white paper suggests a centralized procurement process may help ensure reliability requirements are met.¹⁹ However, this would undermine the ability of CCAs to reflect local customer protection and environmental priorities, and to innovate through procurement decisions.*** The state does not need to establish a centralized procurement model to ensure state goals are achieved. MCE supports strong statewide standards and welcomes dialogue to ensure there are appropriate enforcement mechanisms.

Statewide standards and marketplaces work together to provide a strong electricity market. The resource adequacy (RA) requirement applies to all retail electricity suppliers, is enforced at the CPUC and implemented through the CAISO. This requirement helps to ensure that there is sufficient capacity available on a year-ahead and month-ahead basis and is met through bilateral contracts. The contracts allow the CAISO to call upon these resources if needed to provide their generating capacity to the grid. Similar standards met through planning processes such as the integrated resources planning (IRP) process or through reporting and contracting mechanisms can meet reliability needs without requiring a centralized procurement process.

B. Facilitating a Collaborative Dialogue

The CPUC should expand and strengthen the dialogue between regulators, stakeholders, and the legislature on issues facing the electricity market. The customer choice project has brought together stakeholders on an ad hoc basis to explore issues. MCE proposes to take this process one step further and establish an annual en banc on the State of the Electricity Market.

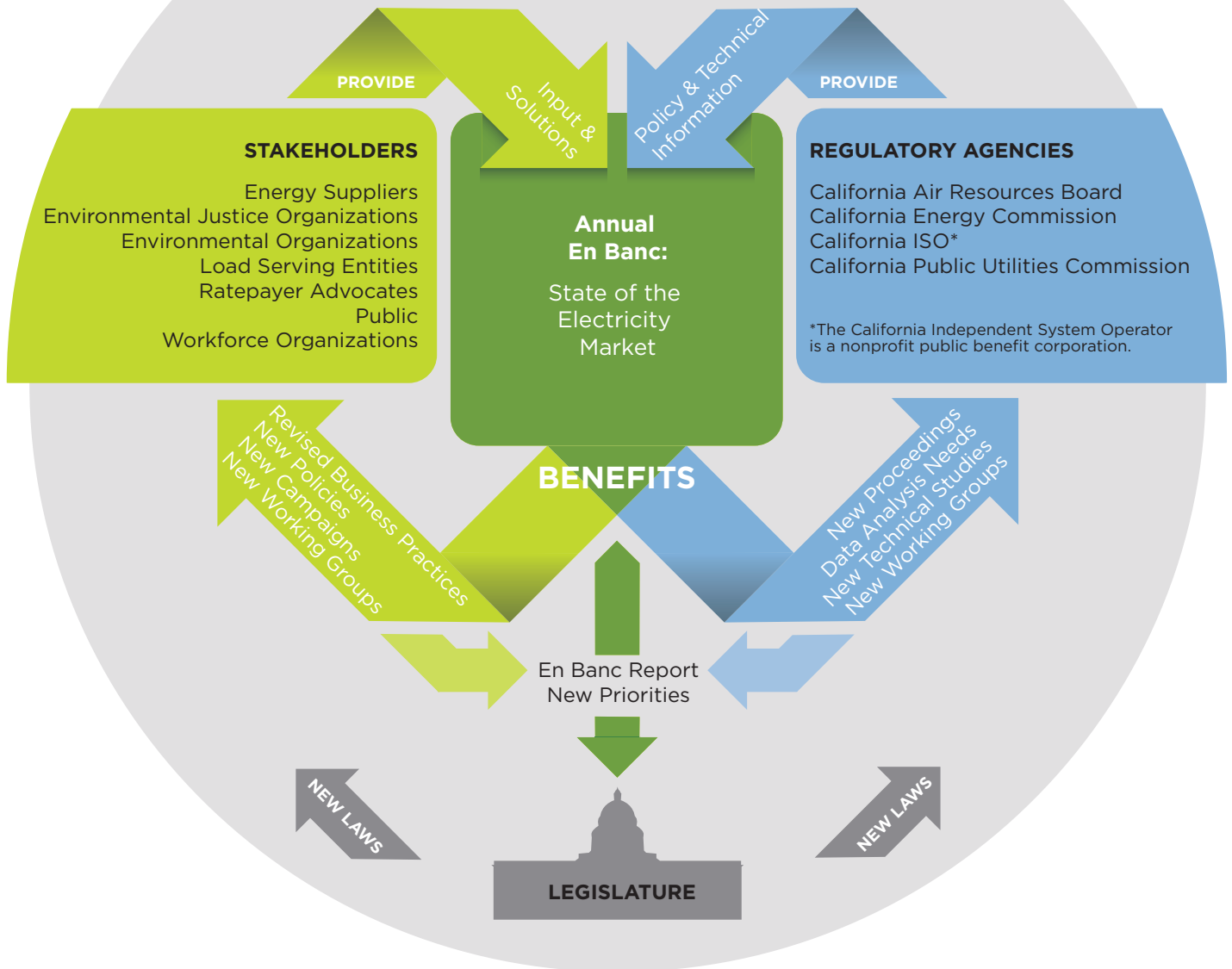
This en banc should be informed through ongoing stakeholder dialogue, perhaps through quarterly meetings, to define the issues and identify any potential data and analysis that are needed in advance of the annual meeting. The en banc should include input from all relevant stakeholders and regulatory agencies and should culminate in an en banc report with input from stakeholders before the report becomes final.

The en banc would be flexible enough to incorporate issues facing the retail and wholesale markets. It would allow exploration of issues ranging from customer choice to reliability to regionalization. The State of the Electricity Market en banc is an important step forward in improving the dialogue between regulators, stakeholders, and the legislature.

¹⁸ Future and archived meeting information is available at <https://www.mcecleanenergy.org/meeting-archive>.

¹⁹ Draft Green Book at p. 57.

EFFECTIVE COLLABORATION & COMMUNICATION



C. Informing and Protecting Customers

MCE appreciates the CPUC’s interest in ensuring customers are informed about their energy choices including the rates and content of their electricity options to avoid becoming unwitting participants.²⁰ Currently, CCAs are legally required to provide multiple opt-out notices to all new customers to inform them about CCA service and provide them with information to opt-out. Additionally, each CCA provides annual notices, including a price comparison of utility rates and a power content label with its sources of electricity. MCE supports the CPUC’s proposal to compile these notices and post the information on a state-administered neutral website to increase customer awareness.

The draft white paper notes that the CPUC currently has authority over customer complaints with utilities but not with CCAs.²¹ There may be a role for the CPUC to serve as a pathway for customer complaints related to CCA billing

²⁰ Draft Green Book at p. 55, 59.

²¹ Draft Green Book at p. 57.

disputes. While it is up to CCAs' governing boards to approve ways to adjudicate those disputes, the CPUC could complement the process by giving customers an avenue for making complaints. The CPUC can channel them to the relevant CCA board for resolution. This provides customers with additional avenues for raising complaints and provides the CPUC insight into customer complaints related to CCA service.

It is important for the CPUC to ensure customer protection for all customers. At present, the CPUC oversees mechanisms to protect utility customers from costs associated with CCA customers moving into or out of utility service. The Power Charge Indifference Adjustment (PCIA) is designed to compensate utilities for contracts they signed on behalf of customers before those customers departed utility service. The PCIA is intended to ensure CCA customers cover the loss utilities would face if they sold this excess power. If a CCA ceases operations, and customers return to utility service and incur costs for utilities, the CPUC recently approved a decision that would require CCAs to post cash, a letter of credit, or a surety bond to cover those costs.²² These are important mechanisms to preserve the principle of customer indifference, which requires no cost-shifting between utility and CCA customers.

The obligation to protect customers also extends to CCA customers, who are still utility customers for T&D service. The CPUC should vigilantly guard against utility efforts to assign inappropriate or unnecessary costs to CCA customers. This can arise through non-bypassable charges (NBCs) to cover costs incurred through utility activity. MCE supports many of the existing NBCs including the DWR Bond costs, the nuclear decommissioning costs, and the public purpose program charges. However, the utilities have proposed additional NBCs that are inappropriate, such as the Clean Energy Charge to subsidize replacement power for PG&E customers in the Diablo Canyon closure proceeding.²³ Such costs can also arise from a utility proposing to recover generation-related costs through T&D rates, effectively subsidizing their generation rates at the expense of all customers (including CCA customers). These proposals are relatively common and CCAs regularly engage to thwart such efforts.

There is a new area of growing concern that the transition of resources from utilities may result in unnecessary costs being created by utilities and borne by CCA customers. As customers depart, the utility has excess resources under contract. Utilities should not simply hold these resources indefinitely, as they may be useful to serve those same departed customers. This is particularly prevalent for local and system reliability. **A utility hoarding these resources will lead to double procurement by the CCA and overinvestment and oversupply of resources in California.**

The CPUC indicates 25% of electricity generation will be provided by non-utilities providers by the end of 2018,²⁴ growing to as much as 85% by the middle of the 2020s.²⁵ If the utilities are permitted to control a large portion of finite and critical resources, there is a risk of market manipulation, which was a significant factor in the energy crisis.

There are four high-level steps that will help address this issue:

- 1) Utilities need to adequately forecast departing load and take steps to adjust their portfolios. This is happening to some degree now.
- 2) The CPUC should work to provide processes and rules that allow utilities to modify their portfolio to account for departing load.
- 3) The CPUC should audit utility portfolios on a bi-annual basis to ensure that resources under contract are appropriate for the size of the utility load.
- 4) The CPUC should monitor the transition of resources from utilities for signs of market manipulation stemming from features such as pricing or timing of sales.

²² This is in reference to the re-entry fee and financial security requirement required of CCAs under California Public Utilities Code Section 394.25(e) that was addressed in the most recent decision in Rulemaking 03-10-003, Decision 18-05-022.

²³ Application 16-08-006.

²⁴ Draft Green Book at p. 4.

²⁵ Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework: Staff White Paper, CPUC, May 2017, at p. 3.

While there is a need for CPUC oversight to avoid market manipulation as utilities sell off resources, MCE recognizes this is not a simple task and requires a balance between bundled customer benefit and unbundled customer burden. ***The CPUC should work to protect all customers by ensuring the costs associated with the transition of resources are reasonable.***

D. Protecting Competitive Neutrality and CCAs as Customers

The CPUC has an important role in preserving competitive neutrality between utilities and CCAs. In addition to the issues discussed in the immediate section above, the CPUC is responsible for implementing a Code of Conduct between utilities and CCAs.²⁶ This provides protections against anti-competitive practices by utilities and prevents a utility funding anti-CCA lobbying with ratepayer funds.

Another element related to competitive neutrality is the fact that CCAs are themselves customers of the utilities. CCAs are required to pay utilities to provide billing services and manage meter data. The CPUC has taken action on multiple occasions to mediate and in some cases order resolution of billing or data issues. The CPUC should continue in this role to enable adequate data sharing and arbitrate disputes related to services utilities provide to CCAs.

E. Cultivating Innovation

The CPUC has made significant advances to support innovation in the electricity market, and should continue to champion innovation guided by the principle of grid neutrality. While the utilities should remain the operators of the T&D grid, they should also ensure that investments made by the private market, ratepayers, or CCAs can help support the grid. This means providing data and incentives that tie resources like energy storage to grid benefits. It also means reducing barriers to interconnection. The CPUC should continue its important work on these issues, and CCAs are willing partners.

The CPUC's energy-related programs also benefit from innovation. The CPUC's recent decision on energy efficiency applications²⁷ is an excellent example. In that decision, the CPUC authorized MCE to serve as a program administrator with a comprehensive set of offerings alongside utilities and other local government administrators. The CPUC also required the utilities to outsource the design of 60% of programs by 2020 to bring in new ideas from the private market. A diversity of approaches brings innovation. This trend is growing in energy efficiency but needs to be accelerated and expanded to other areas such as electric vehicle programs. The CPUC should ensure that energy-related programs continue to be funded in a manner that allows fair competition and access to funds among utilities and CCAs.

F. Advancing Equity

CCAs have a strong interest in advancing equity and envision the CPUC as a partner. The CCA status as a local government agency and requirement to serve residential customers create structural drivers to focus on long-term price stability and consistent service to customers. Many CCAs serve low-income and disadvantaged communities within their service area. As a result, MCE and CCAs generally focus on bringing cleaner power to everyone, at rates that are often below the incumbent utilities. This empowers customers who may not otherwise be able to install solar panels or own an electric vehicle to reduce their carbon footprint and address climate change without paying a premium.

CCAs also help advance policy and on-the-ground solutions related to social equity and environmental justice.

MCE's workforce practices include observing local hire requirements and career development opportunities for formerly incarcerated individuals. The CPUC has supported MCE's efforts to serve income-qualified customers through the Low-Income Families and Tenants (LIFT) energy efficiency pilot program. This program seeks to serve a hidden community of customers and identify barriers to participation in low-income energy efficiency programs.

²⁶ Senate Bill 790 (2011) required a Code of Conduct. The CPUC established the Code of Conduct in Decision 12-12-036.

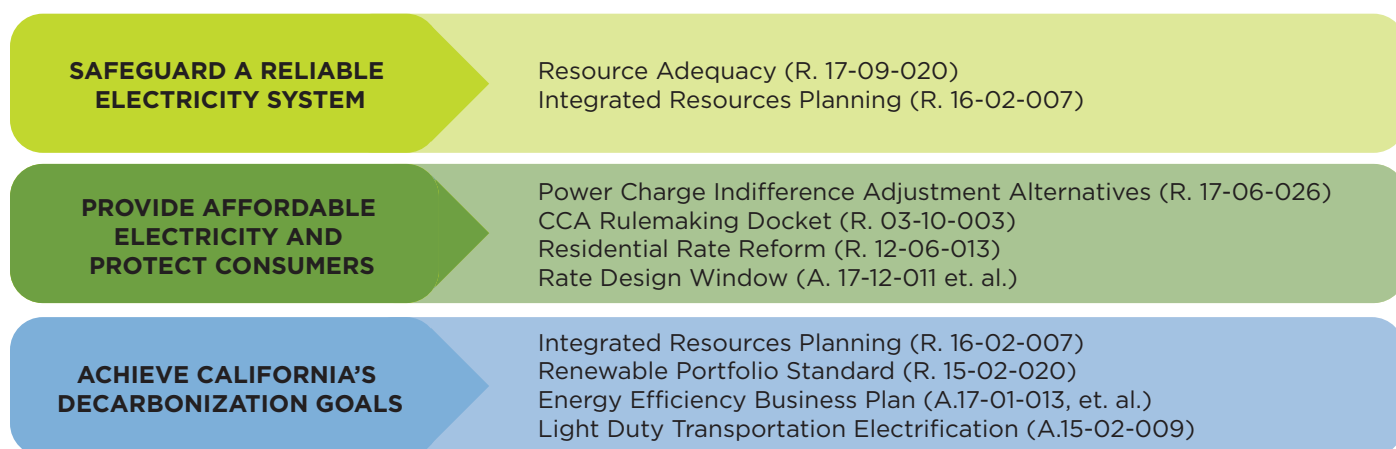
²⁷ Decision 18-05-041 in Application 17-01-013 et al.

The CPUC also recently adopted MCE’s policy recommendation to allow disadvantaged communities to meet the geographic criterion of the definition of hard-to-reach customer, which improves program delivery to those customers particularly in major metropolitan areas.²⁸

MCE supports universal availability of equity programs such as the California Alternate Rates for Energy (CARE) discount. It is appropriate for all customers to support certain policy objectives such as the CARE discount to ensure a minimum set of programs are available to ratepayers throughout California. Supplemental programs may be funded by individual load serving entities through generation revenue such as MCE’s low-income solar rebate program. The CPUC should continue to support universal equity programs and include CCAs in their delivery.

G. Recommendation: CPUC Charts the Path to the Future

CCAs are active participants in many of the proceedings related to the state goals mentioned in the draft white paper. The chart below provides an overview of CCA participation in those proceedings, and proposes additional issues that can be addressed at the Commission to increase collaboration and encourage electricity market innovation and transformation.



SAFEGUARD A RELIABLE ELECTRICITY SYSTEM	
VISION	Ensure that all load serving entities are working in collaboration to provide safe and reliable electricity services to California ratepayers.
KEY OBJECTIVES	A. Responsibilities and costs for reliability resources are fairly allocated. B. Load migration is regularly updated to inform system and local reliability needs.
EXISTING PROCEEDINGS RELATED TO RELIABILITY	<p>Resource Adequacy 2018 (R. 17-09-020) proceeding contemplates the following:</p> <ol style="list-style-type: none"> 1. RA program reforms to maintain reliability and reduce costly backstop procurement. 2. Multi-year RA requirements. 3. Refinements to rules and requirements for local area RA, Flexible RA, backstop procurement costs. <p>Integrated Resources Planning (R. 16-02-007) implements the following elements related to reliability:</p> <ol style="list-style-type: none"> 1. LSEs are directed to provide IRPs that demonstrate consideration of reliability costs and procurement. 2. Determine system-wide renewable integration needs and identify paths to procure for those needs.
OTHER ACTIONS TO CONSIDER	A. Fair allocation of responsibilities and costs of emergency planning and response. B. The role of the Provider of Last Resort in a transitioning marketplace, as well as post-transition to be considered in R. 03-10-003.

²⁸ These are a sample of MCE’s equity initiatives, Appendix III has additional information.

PROVIDE AFFORDABLE ELECTRICITY AND PROTECT CONSUMERS

VISION

Ensure customers, regardless of their service providers, have access to affordable rates and high-quality customer protection.

KEY OBJECTIVES

- A. Costs of maintaining steady electricity supplies are fairly allocated between bundled and unbundled customers.
- B. Portfolios are carefully managed to ensure affordable rates for all customers and to ensure utilities sell excess supply back into the market.
- C. Ratepayers receive accurate information about available electricity products to make informed choices.
- D. Adequate measures are in place to address bill delinquency and repayment plans.

EXISTING PROCEEDINGS RELATED TO AFFORDABILITY AND RATEPAYER PROTECTION

Power Charge Indifference Adjustment Alternatives (R. 17-06-026) addresses the key elements related to ratepayer indifference:

- 1. Fair cost allocation of above-market costs of existing investor owned utilities' contracts.
- 2. Mitigate cost impact on low-income and disadvantaged customers.
- 3. Determine a pathway to minimize costs for ratepayers given the increasing departing load.

The CCA Rulemaking Docket (R. 03-10-003) established a bond to be posted by individual CCAs to:

- 1. Ensure that existing customers of an investor owned utility are protected from potential costs if large numbers of CCA customers involuntarily return to an investor owned utility.
- 2. Appropriately cover the administrative and incremental procurement costs incurred by the investor owned utility.

The Residential Rate Reform proceeding (R. 12-06-013) and the consolidated Rate Design Window applications (A. 17-12-011 et. al.) contemplate and implement the following:

- 1. Reasonable residential rate structures that incentivize load shifting to reduce the need for evening peak resources.
- 2. The process for enabling CCA's customers to utilize time-of-use rates.
- 3. The marketing, education, and outreach to CCA customers during the rate schedule transition.

OTHER ACTIONS TO CONSIDER

- A. Process to provide all CCAs with settlement quality metered data to inform procurement decisions, load forecasting, and demand response programs that best meet each CCA's demand.
- B. Provide each CCA with the flexibility to create rate schedules that best meet the needs of their customers, without having to mirror an existing IOU rate schedule.
- C. Address policies to ensure utilities sell excess supply in the PCIA docket R. 17-06-026.

ACHIEVE CALIFORNIA'S DECARBONIZATION GOALS

VISION

Ensure that all procurement practices undertaken by LSEs will meet California's environmental policy goals and standards.

KEY OBJECTIVES

- A. All load serving entities will meet the Renewable Portfolio Standard set and updated by the legislature.
- B. All load serving entities will achieve the mandated greenhouse gas emissions reduction targets set by the California Air Resources Board.
- C. All load serving entities will consider, evaluate, develop, and implement programs to shift or reduce demand to lessen the need for fossil fuel peaking plants.
- D. All load serving entities will consider, evaluate, develop, and implement programs to increase transportation electrification.

EXISTING PROCEEDINGS RELATED TO AFFORDABILITY AND RATEPAYER PROTECTION

The Integrated Resources Planning proceeding (R. 16-02-007) directs the LSEs to achieve greenhouse gas emissions benchmarks set by the CARB, procure 50% of their portfolios from RPS-eligible resources, minimize ratepayer impacts, consider impact on disadvantaged communities, and meets renewable integration needs. In accomplishing these goals, stakeholders are engaging in the proceeding to determine:

- 1. A streamlined planning process that tracks LSEs' actions in achieving decarbonization and reliability goals.
- 2. Collaboration and coordination process between the CPUC and the CCA local governing boards that respect each other's jurisdictional authority.

All LSEs, including CCAs, continue to participate in the RPS proceeding (R. 15-02-020) to implement various elements of the RPS program, including:

- 1. Modifying the RPS program requirements when directed by the legislature.
- 2. Filing annual RPS compliance plans and reports.

Under Public Utilities Code 381.1, CCAs have the ability to elect or apply to administer Commission-approved energy efficiency programs to further reduce electricity sector GHG emissions. The most recent decision in the Energy Efficiency Business Plan proceeding (A.17-01-013, et. al.) approved MCE's proposal to expand its energy efficiency programs.

CCAs have also actively participated in various transportation electrification proceedings, as well as energy storage proceedings. While the focus has largely been on fair cost recovery to ensure that CCA customers do not pay for programs they cannot participate in or benefit from, CCAs and the IOUs can work to collaborate in these proceedings as well. For instance, MCE and Sonoma Clean Power entered into a settlement agreement with PG&E in PG&E's light duty transportation electrification application (A.15-02-009).

VI. Important Clarifications: Utilities Can Forecast and Generators Transact with CCAs

The draft white paper asserts that CCAs create uncertainties for market participants related to utility forecasts and generators selling capacity to new market entrants.²⁹ ***This claim of uncertainty caused by CCAs is unsupported by evidence and should be removed from the draft.***

Utilities are capable of planning for CCA load departure. Utilities conduct sophisticated forecasting and plan for more volatile factors such as weather and drought conditions. CCAs launch through a straightforward public process and have low and stable opt-out rates (typically less than 20% of customers). Utilities often closely track the progress of efforts related to CCA formation and have a history of actively opposing such efforts, which led to the passage of SB 790 (2011) and the CPUC's Code of Conduct decision D.12-12-036. The CPUC should hold the utilities accountable for adequately forecasting load and managing their portfolios.

Suppliers of capacity and electricity have learned to trust the CCA model through the strong track records and financial conditions of existing CCAs. As the first CCA, MCE made great strides in familiarizing the supplier and financial community with the CCA business model. In fact, MCE was recently assigned an investment grade credit rating by Moody's.³⁰ Even new CCAs launching today have robust responses to their solicitations from generators. The market has grown to understand and embrace the new opportunities presented by CCAs.

VII. Conclusion

CCAs bring an important choice to customers and a healthy diversity to California's electricity market. CCAs, as local governments, support regulation and supplement statewide requirements with local preferences. The utilities have an important and enduring role in managing the T&D grid and providing customers a choice for generation service. The CPUC has tremendous responsibilities to support state goals and protect customers, and is well situated to facilitate a dialogue and help chart the path to the future. MCE is a willing and eager partner and looks forward to the continued growing collaboration and communication on these important issues.

²⁹ Draft Green Book at p.16.

³⁰ Moody's assigns Baa2 issuer rating to Marin Clean Energy (CA) (MCE) ; stable outlook, May 16, 2018. Available at https://www.moody's.com/research/Moodys-assigns-Baa2-issuer-rating-to-Marin-Clean-Energy-CA--PR_904552608.

Appendix I: Sample of Compliance Requirements

Compliance Requirements

Report	Frequency	Entity
Resource Adequacy (Load Forecast-Year Ahead)	Annual	CEC/CPUC
Resource Adequacy (Compliance Demonstration: System, Local, Flexible)	Monthly	CPUC
Resource Adequacy (Year Ahead Compliance Demonstration Local/System)	Annual	CEC/CPUC
Resource Adequacy (Historical Load Data)	Annual	CEC
Resource Adequacy (Price Data Request)	As Requested	CPUC
Resource Adequacy (Load Forecast Updates)	As Needed	CEC
Flexible Capacity Needs Report	Annual	CAISO
IEPR-Demand Forecast and Resource Plans	Biennial	CEC
IEPR-Resource Plans Updates	Biennial	CEC
Power Source Disclosure	Annual	CEC
QFER 1306B	Quarterly	CEC
Officer Certification	Annual	CAISO
Annual Retail Sales Report	Annual	CARB
Wind Power Purchases-Form 1386	Quarterly	CEC

Report	Frequency	Entity
RPS Report	Annual	CPUC
RPS Closing Report	As Requested	CEC/CPUC
EIA 826	Monthly	DOE
EIA 861	Annual	DOE
WREGIS REC Retirement Report	Annual	WREGIS
AMI Data Privacy Audit	Triennial	CPUC
AMI Data Privacy Report	Annual	CPUC
Energy Storage Tier 2 Advice Letter	Biennial	CPUC
GHG Emission Performance Standard Advice Letter	Annual	CPUC

*This table intended to serve as a sample of CCA compliance obligations.

Appendix II: MCE Procurement Information

TOGETHER WE'RE BUILDING A CLEANER ENERGY FUTURE FOR CALIFORNIA | 2018

From 2010–2016, MCE customers have **eliminated more than 199,295 metric tons of greenhouse gas emissions** — the equivalent of removing 42,676 cars from the road for one year or sequestering the same amount of carbon as 234,741 acres of forest in one year.¹

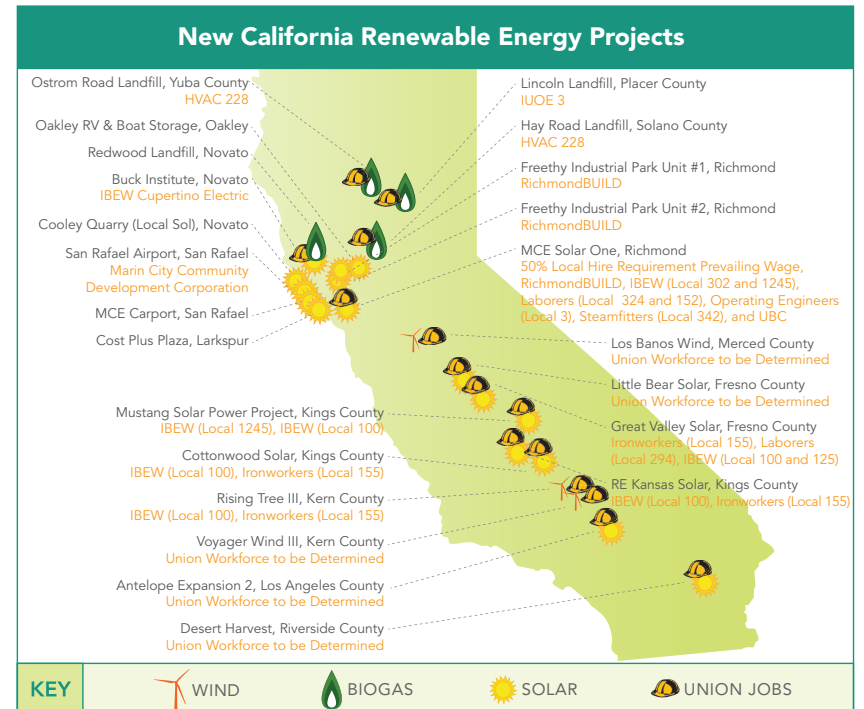
BUILDING NEW RENEWABLES

MCE and its partners have committed over **\$1.6 billion to build 813 MW of new renewable energy projects in California**. This includes \$905 million for solar, \$665 million for wind, and \$25 million for biogas projects. MCE was likely California's largest purchaser of renewable energy in 2016. Below is a list of MCE's new California renewable energy projects currently under contract.

	RESOURCE & CONTRACT TYPE ²	RESOURCE PROVIDER / PROJECT NAME	LOCATION	PROJECT CAPACITY (MW)	MCE SERVICE START DATE	CONTRACT LENGTH (YEARS)
LOCAL (MCE Service Area)	Solar FIT	San Rafael Airport	San Rafael, Marin Co.	1	2012	20
	Solar PPA	Dominion / Buck Institute of Research on Aging	Novato, Marin Co.	1	2016	25
	Solar FIT	Rawson, Blum & Leon / Cost Plus Plaza	Larkspur, Marin Co.	0.265	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #1	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	North Shore Solar Partners LLC / Freethy Industrial Parkway Unit #2	Richmond, Contra Costa Co.	1	2016	20
	Solar FIT	REP Energy / Cooley Quarry	Novato, Marin Co.	1 Local Sol ³	2017	20
	Biogas PPA	Waste Management / Redwood Landfill	Novato, Marin Co.	3.6	2017	20
	Solar PPA	MCE / Solar One	Richmond, Contra Costa Co.	10.5	2017	25
	Solar FIT	Hayworth-Fabian, LLC / Oakley RV & Boat Storage	Oakley, Contra Costa Co.	1	2018	20
	Solar PPA	MCE / Carport Shade Structure	San Rafael, Marin Co.	0.08	2018	20
NEARBY (<100 Miles)	Biogas PPA	G2 Energy / Hay Road Landfill	Vacaville, Solano Co.	1.6	2013	18
	Biogas PPA	Genpower / Lincoln Landfill	Lincoln, Placer Co.	4.8	2013	20
	Biogas PPA	G2 Energy / Ostrom Road Landfill	Wheatland, Yuba Co.	1.9	2013	18
IN STATE (Within California)	Solar PPA	Dominion / RE Kansas Solar	Stratford, Kings Co.	20	2015	3
	Solar PPA	Dominion / Cottonwood Solar	Stratford, Kings Co.	23	2015	25
	Wind PPA ⁴	EDP Renewables / Rising Tree III	Mojave, Kern Co.	99	2015	3.5
	Solar PPA	Recurrent Energy / Mustang Solar Power Project	Lemoore, Kings Co.	30	2018	15
	Solar PPA	Sempra / Great Valley Solar	Tranquillity, Fresno Co.	100	2018	25
	Solar PPA ⁴	sPower / Antelope Expansion 2	Lancaster, Los Angeles Co.	105	2018	20
	Wind PPA	Terra-Gen / Voyager Wind III	Mojave, Kern Co.	42	2018	12
	Wind PPA	Terra-Gen / Los Banos Wind	Los Banos, Merced Co.	125	2018	12
	Solar PPA	First Solar / Little Bear Solar	Mendota, Fresno Co.	40 up to 160 ⁵	2020	20
	Solar PPA ⁴	EDF Renewables / Desert Harvest	Desert Center, Riverside Co.	80	2020	20

2,800+ CALIFORNIA JOBS

MCE's renewable projects have supported more than 2,800 California jobs⁶ resulting in 1.3 million union labor hours. MCE's sustainable workforce policy outlines support for local businesses, union members, training and apprenticeship programs, and support for green and sustainable businesses.



1. Based on MCE's aggregate portfolio emission factor and the EPA's greenhouse gas equivalencies calculator at: epa.gov/energy/greenhouse-gas-equivalencies-calculator
2. FIT=Feed-In Tariff; PPA=Power Purchase Agreement
3. 100% solar energy service option produced by a local solar farm within MCE's service area.
4. Complies with CPUC's G.O. 156 Utility Supplier Diversity Program.
5. Project size will increase to 160 MW with inclusion of new MCE communities.
6. MCE uses the National Renewable Energy Laboratory's Jobs and Economic Development Impacts Model to provide consistent and reasonably accurate estimates of direct and indirect jobs involved in MCE's power contracting efforts and general operations.

FOR MORE INFORMATION:
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info@mceCleanEnergy.org



A LOCAL RENEWABLE PROJECT TIMELINE | MCE SOLAR ONE IN RICHMOND, CA

MCE Solar One's 10.5 MW solar system is expected to produce 22,000 megawatt-hours per year of pollution-free electricity, which is enough energy to power over 3,900 homes. The project concept was initially conceived by the Richmond community as a way to include renewable energy and solar facilities in the Chevron Modernization Project.

ENVIRONMENTAL BENEFITS

The amount of renewable electricity generated at MCE Solar One in one year is equivalent to*:

- » Eliminates 3,234 metric tons of carbon dioxide in one year
- » Taking more than 680 fossil-fuel cars off of the road for one year
- » The carbon sequestered by 3,045 acres of forest in one year

* Based on MCE's aggregate portfolio emission factor and the EPA's greenhouse gas equivalencies calculator at: epa.gov/energy/greenhouse-gas-equivalencies-calculator

PUBLIC BENEFITS

- » Repurposes 60 acres of a remediated brownfield site
- » Provides clean, local, renewable energy
- » Supports 341 jobs
- » Partners with job-training program RichmondBUILD that helps retool local residents for construction and clean energy jobs
- » Aims to maximize local economic benefits by requiring 50% local resident workforce and engaging Richmond-based contractors and suppliers

- » Richmond community identifies an opportunity for Chevron to include renewable energy features in the Chevron Modernization Project
- » MCE has a preliminary discussion with Richmond and Chevron about developing a solar farm on a remediated brownfield site on refinery property
- » MCE conducts a feasibility study

- » MCE acts as Lead Agency for the Environmental Impact Report of the project and filed Notice of Determination
- » MCE secures Design Review Board approval
- » MCE receives utility interconnection from PG&E

- » Developers partner with job training program RichmondBUILD and local contractors to meet local hire requirement
- » Construction began in Q2 2017
- » Commercial operation began in Q4 2017
- » Solar One becomes the Bay Area's largest public-private solar partnership
- » MCE purchases all of the energy generated at the local project
- » MCE to become project owner in 6-7 years
- » MCE hosts a ribbon cutting ceremony

2013

2014

2015

2016

2017 & BEYOND

- » Richmond City Council negotiated and approved the Environmental and Community Investment Agreement to include a \$1/year land lease
- » Site offered to MCE to develop a solar farm for community benefit
- » Richmond requires a minimum 50% local hire for Richmond residents
- » MCE consults with and receives endorsement from Community Power Coalition about building solar project on Chevron land
- » MCE begins to identify developers for Chevron Modernization Project
- » MCE applies for interconnection with PG&E

- » MCE issues a request for proposal for construction and financing services
- » MCE engages with Cenergy and sPower to build and finance the project, respectively
- » MCE submits building permit
- » MCE hosts a groundbreaking ceremony



Appendix III: MCE Environmental Justice Information



Ruben Pedroza and family, MCE customer and RichmondBUILD graduate

MCE Environmental Justice

MCE provides our low-income and disadvantaged communities with a wide range of energy efficiency and renewable energy offerings. MCE's Low-Income Families and Tenants (LIFT) pilot program provides additional incentives to reach hidden communities. We also provide multilingual material to increase access and awareness of services and programs in our communities.

MCE Energy Efficiency Offerings

MCE currently administers energy efficiency programs in three key areas: multifamily, single family and small commercial. Due to CPUC requirements, MCE's current programs are limited to innovative offerings and areas not well served by other programs.

HIGHLIGHT: MCE'S MULTIFAMILY OFFERINGS

Since 2012, MCE has provided energy efficiency services to multifamily residences, which have included:

- » Energy assessments
- » Energy and water saving measures for tenant units
- » Technical assistance

DID YOU KNOW?

In 2017...

- » MCE distributed \$408,000 in rebates to affordable properties by serving 760 units.

In 2017...

- » MCE committed another \$393,975 in rebates for affordable properties.

AS OF DECEMBER 31, 2017, MCE HAS:

ACHIEVED
**2326 MWH &
 97,630 THERMS**
 OF ENERGY
 SAVINGS

SAVED
**16.9
 MILLION**
 GALLONS
 OF WATER

AUDITED
97
 MULTIFAMILY
 PROPERTIES

DISTRIBUTED
\$933K+
 IN REBATES

PROVIDED
1,733
 UNITS WITH ENERGY
 SAVING EQUIPMENT

MCE Renewable Energy Offerings Available to Low-Income Customers

SOLAR INCENTIVES

For the 2012-2019 fiscal years, MCE allocated \$345,000 toward low-income solar rebates, partnering with GRID Alternatives to offer \$900 rebates to low-income customers who install solar panels. Program participants have saved an estimated \$2,002,719 on their monthly utility bills.

DISCOUNTED RATE

Low-income customers are able to receive the California Alternate Rates for Energy (CARE) discounted energy rate in full with MCE. Our customers are also eligible for financial assistance from the Family Electric Rate Assistance (FERA) and Energy Savings Assistance Program (ESAP).

MORE RENEWABLES

A just transition toward a sustainable clean energy economy means ensuring that all customers, regardless of income, have access to renewable energy. MCE's Board of Directors, composed of elected officials, are accountable to their constituents, our customers. Part of MCE's mission is to provide stable, competitive rates for all community members. All MCE customers receive 50% renewable energy by default. Those who opt up to MCE's 100% renewable option pay 1¢/kWh more. Half of this premium goes toward the build out of new, local, renewable energy projects, promoting investment and green-collar jobs within our service area.



2,800+ TOTAL CALIFORNIA JOBS

MCE's commitment to our communities and the environment extends beyond supplying renewable power. We partner with local organizations and businesses to bring jobs home by investing in new, local, renewable energy development. In addition, our contracted power projects have supported more than 2,800 California jobs. MCE follows a Sustainable Workforce Policy, adopted by MCE's Board of Directors.

MCE SOLAR ONE

MCE has partnered with solar developer Cenergy Power to build what will be the largest public-private solar partnership in the Bay Area, MCE Solar One. The 60 acre, 10.5 MW ground mounted solar farm in Richmond, CA supported 341 jobs and provides power for 3,900 homes per year. This project employed approximately 50% local labor, guaranteeing local benefits through clean energy job creation. MCE Solar One provided jobs to workers from the following unions: UBC and Laborers Union (Local 152); IBEW (Local 302); IBEW (Local 1245); Laborers Union (Local 324); Operating Engineers (Local 3) and Steamfitters (Local 342). MCE contracted with job-training program RichmondBUILD to train and hire local workers to construct MCE Solar One.

MCE'S LOW-INCOME FAMILIES AND TENANTS (LIFT) PILOT PROGRAM

- » Blends the LIFT pilot with MCE's existing Multifamily Energy Savings Program to maximize incentives, achieve deeper energy savings, and streamline administrative processes.
- » Works closely with community-based organizations, local housing agencies, and affordable housing nonprofits to identify property owners and managers interested in completing energy efficiency upgrade projects, enabling participation from low-income residents who avoid programs based on real or perceived barriers (e.g., privacy and immigration status).
- » Serves as a Single Point of Contact for property owners and managers by providing and bundling demand-side opportunities, phasing projects to incorporate additional technologies over time, connecting them to available financing programs, and assisting them in leveraging and streamlining the enrollment process for other MCE programs and income qualified resource conservation programs.
- » Creates opportunities to fuel switching from natural gas combustion and propane appliances to electric heat pumps to support cleaner and more efficient energy use while resolving health and safety concerns.

MCE COMMUNITY POWER COALITION

MCE's Community Power Coalition was formed in 2014 to cultivate a deep and dynamic relationship with ratepayer advocates and community-based organizations that focus on the interests of underrepresented and historically marginalized constituencies. The mission of the Coalition focuses on:

- » Expanding access to affordable renewable energy and energy efficiency programs;
- » Advancing equitable, local, and sustainable workforce and economic development;
- » Accelerating the transition to a cleaner and more efficient energy economy; and
- » Building and developing inclusive programs and policies for all communities in MCE's service area.

Representing a wide range of interests, coalition members include Communities for a Better Environment and the Sierra Club. With its coalition partners, MCE completed its own assessment of low-income needs in 2016. The top priorities were receiving energy efficiency and solar rebates, lowering electricity rates, and promoting development of local renewables.



FOR MORE INFORMATION, PLEASE CONTACT:

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

Order Instituting Rulemaking to Develop a Successor)	
to Existing Net Energy Metering Tariffs Pursuant to)	
Public Utilities Code Section 2827.1, and to Address)	Rulemaking 14-07-002
Other Issues Related to Net Energy Metering.)	(Filed July 10, 2014)
)	

**OPENING COMMENTS OF THE CCA PARTIES
ON THE REVISED ALTERNATE PROPOSED DECISION**

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Dated: June 11, 2018

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

Order Instituting Rulemaking to Develop a Successor)	
to Existing Net Energy Metering Tariffs Pursuant to)	
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Other Issues Related to Net Energy Metering.)	(Filed July 10, 2014)
)	

**OPENING COMMENTS OF THE CCA PARTIES
ON THE REVISED ALTERNATE PROPOSED DECISION**

In accordance with Rule 14.3 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure, the City of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”), Peninsula Clean Energy Authority (“PCE”), and Sonoma Clean Power Authority (“SCP”) (collectively, “CCA Parties”) hereby submit these comments on the *Revised Alternate Proposed Decision of Commissioner Guzman-Aceves* (“Revised Alternate PD”) in the above-captioned proceeding.¹

I. INTRODUCTION

The CCA Parties share and fully support the Commission’s goal of ensuring that Disadvantaged Communities (“DACs”) have robust access to affordable renewable energy options. As local governmental agencies, Community Choice Aggregators are well positioned to be a complementary and catalytic partner with the Commission in advancing local programs aimed at expanding renewable energy programs for DACs. Community Choice Aggregators have initiated certain programs to date to increase access to distributed energy resources in DACs and will continue to do so. This proceeding provides a continuing opportunity for the

¹ Pursuant to Rule 1.8(d) of the Commission’s Rules of Practice and Procedure, MCE, PCE, and SCP have given counsel for the City of Lancaster permission to sign these comments on their behalf.

Commission to expressly welcome, accommodate and promote involvement from Community Choice Aggregators in this important endeavor. The CCA Parties are encouraged by the prospect of greater collaboration with the Commission on renewable energy programs for DACs.

Beyond being an opportunity to collaborate, as a matter of law and fundamental fairness, DAC renewables energy programs authorized by the Commission that use greenhouse gas (“GHG”) allowance proceeds and public purpose program (“PPP”) funds must be equally available to bundled and unbundled customers (in form *and* practice) and must otherwise be competitively neutral as between the investor-owned utilities (“IOUs”) and Community Choice Aggregators. As currently written, the Revised Alternate PD fails to clearly articulate and expressly apply these requirements. This is understandable in many respects because articulating and applying “competitive neutrality” requirements is a relatively new undertaking for the Commission and the programs developed in this proceeding are still nascent. However, this undertaking is necessary not only as a matter of law, but also to enable the Commission to optimize the local advantages offered by Community Choice Aggregators, particularly in the realm of DAC programs.

Thankfully, various principles and a general model exist for application of the competitive neutrality requirement. In the context of demand response (“DR”) programs, the Commission has articulated certain requirements and set forth various processes to ensure competitive neutrality between the IOUs and Community Choice Aggregators. While not a perfect analog, the DR process provides a helpful model that can be further developed in this context. The CCA Parties request that the Revised Alternate PD be expanded (a) to include express articulation of the competitive neutrality requirements and (b) to describe the general

framework for post-decision processes to implement and apply these requirements, borrowing on the Commission's work in the context of DR programs.

II. COMMENTS

A. The Law Requires That GHG Funds Be Allocated And Made Available On A Non-Discriminatory And Competitively Neutral Basis

As would be expected, the law makes clear that funds derived from GHG allowance proceeds should be allocated and made available in a non-discriminatory, competitively neutral manner. For example, Section 95892(d)(4) of the California Air Resources Board's ("CARB") Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms requires that "[i]nvestor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators" in the use of allowance proceeds."² Additionally, in the context of GHG compliance costs, the Commission specifically required that the IOUs include GHG compliance costs in generation rates to ensure competitive neutrality.³ Likewise, in the context of GHG allowance proceeds, on which the Alternate Revised PD relies,⁴ the IOUs are not portrayed as the *exclusive* administrators of clean energy programs under statute, but rather Community Choice Aggregators, as qualified third-parties, are also authorized to administer such programs.⁵

² 17 CCR § 95892(d)(4).

³ See Decision ("D.")12-12-033 at 84; Finding of Fact 136 ("To ensure competitive neutrality among investor-owned utilities and CCAs and Energy Service Providers, GHG compliance costs must be included in the generation component of customers' rates and allocated in the same manner that other generation costs are allocated to bundled customers.").

⁴ See, e.g., Alternate Revised PD at 53.

⁵ See Pub. Util. Code §748.5(c).

These specific requirements for GHG costs and proceeds are in harmony with broader statutory principles addressing the relationship of the IOUs vis-à-vis Community Choice Aggregators. As a general matter, in the context of Community Choice Aggregation (“CCA”) programs, the Commission is called upon to “foster fair competition and protect against cross-subsidization by ratepayers.”⁶ More broadly, the Commission has been particularly mindful of the chilling effect on innovation that can result if generation costs are not properly applied.⁷

The Revised Alternate PD appears to generally acknowledge the requirement of non-discrimination and competitive neutrality. In addressing comments made by MCE regarding the use of GHG allowance proceeds, the Revised Alternate PD affirms that “...our DAC-Green Tariff would be open to both bundled and unbundled customers to the extent that CCAs and DA providers offer the program to their customers.”⁸ This, however, is the only statement in the Revised Alternate PD about non-discrimination and competitive neutrality.

While the law is clear on the requirement of non-discrimination and competitive neutrality, its practical application is challenging. To ensure programs can be implemented quickly, the CCA Parties strongly believe that additional articulation is needed in the Revised Alternate PD with respect to policy statements and post-decision processes. A failure to do so risks running afoul of legal requirements and may discourage Community Choice Aggregators from developing Community Solar Green Tariff programs, thereby compromising the

⁶ See Pub. Util. Code §707(a)(4)(A). See also Pub. Util. Code § Section 366.2(a)(4), which specifically prohibits the shifting of costs between CCA customers and bundled service customers.

⁷ See generally D.97-08-056 at 8 (“We will not permit allocations of generation cost to distribution customers [because to] do so would compromise market efficiency by producing artificially low utility generation rates...and provide competitive advantages, which would stifle competition to the utilities.”).

⁸ Revised Alternate PD at 53.

opportunity that exists for the Commission and Community Choice Aggregators to collaboratively pursue the development of renewable energy DAC programs, as envisioned under law.

If there are reasons why the Commission is unwilling in this context to articulate and apply the competitive neutrality requirement, the Commission must only assign DAC program costs to bundled customers. This is so because “if a program or tariff is only available to bundled customers, that program’s costs shall be allocated solely to generation rates.”⁹ If, *as a practical matter*, Community Choice Aggregators or their customers cannot “easily” or meaningfully participate in the program, or if participation would violate competitive neutrality principles, cost causation principles require that CCA customers not bear these costs.¹⁰ The CCA Parties would strongly prefer that the Revised Alternate PD be clarified to articulate and apply the competitive neutrality requirement. However, if the Commission does not do this, the Commission must only assign DAC program costs to bundled customers.

B. A Relatively Ready-made Model Exists For Applying The Non-Discrimination and Competitive Neutrality Requirement

The Commission should take note of the extensive work on competitive neutrality that has taken place in the context of DR programs. The CCA Parties believe that this work can be replicated, in part, and extended to the Community Solar Green Tariff program.

⁹ See D.14-12-024 at 48.

¹⁰ See generally D.12-12-004 at 52-55 (finding that, in the context of dynamic pricing programs and tariffs, it is inappropriate to charge direct access and CCA customers for costs if they cannot easily participate in the associated programs or if they do not significantly benefit from the costs).

In D.14-12-024, based on input and comments from MCE, the Commission adopted competitive neutrality requirements for DR programs.¹¹ In D.14-12-024, the Commission expressly acknowledged that a barrier exists in the development of DR programs by Community Choice Aggregators.¹² In response, as a partial measure, the Commission adopted competitive neutrality requirements pertaining to cost-recovery in situations in which a Community Choice Aggregator offers a DR program. After adopting this requirement, the Commission set further procedural steps “to determine how to implement the competitive neutrality requirement.”¹³ In D.17-10-017, after workshops and other procedural means of informing the record, the Commission adopted additional measures to implement the competitive neutrality requirement.

While not a perfect analog, DR programs have attributes similar to the proposed Community Solar Green Tariff program. In D.17-10-017, the Commission stated that it balanced competing objectives: “ensuring fair competition between the Utilities’ demand response programs and those provided by Community Choice Aggregator[s]...[while also ensuring that the Commission] is meeting the adopted demand response goal whereby Commission regulated demand response programs assist the State in meeting its environmental objectives....”¹⁴ In D.17-10-017, the Commission also considered “regulatory oversight,” and eventually concluded that “the use of the Tier Three Advice Letter process strikes a balance of expediency, transparency, and the appropriate level of regulatory oversight.”¹⁵

¹¹ See generally D.14-12-024 at 48-50.

¹² See D.14-12-024 at 49.

¹³ D.14-12-024 at 50.

¹⁴ D.17-10-017 at 15.

¹⁵ D.17-10-017 at 17. The Commission also instructed the Energy Division to “review the level of regulatory oversight...and recommend to the Commission whether a more or less stringent approach is necessary in the future.” (D.17-10-017 at 17.)

Again, the competitive neutrality requirements established in the context of DR programs are not a perfect analog. For one thing, the requirements largely apply to cost-recovery rules, and do not specifically address how Community Choice Aggregators may receive funding on equal footing with the IOUs to support development of CCA programs, while respecting the statutory authority given to local CCA governing boards to control their programs and policies. Nevertheless, there is much that the Commission can glean from the DR requirements in shaping rules for the Community Solar Green Tariff program. The CCA Parties are committed to working with the Commission as it develops these important rules.

C. The Revised Alternate PD Should Establish Basic Principles For Non-Discrimination and Competitive Neutrality, And Should Establish Further Activities To Implement These Principles

As noted above, the only reference in the Revised Alternate PD to non-discrimination and competitive neutrality is that the “DAC-Green Tariff should be open to both bundled and unbundled customers to the extent that CCAs and DA providers offer the program to their customers.”¹⁶ No mention is made as to how, as a practical matter, Community Choice Aggregators can offer the DAC-Green Tariff to their customers on *competitively neutral* basis, nor is there any mention of whether or not this same opportunity exists for the Community Solar Green Tariff program, which is created in Section 6.5 of the Revised Alternate PD and which has particular appeal to Community Choice Aggregators. While, as reflected in D.14-12-024 with respect to DR programs, *extensive* statements need not be included in the final decision, it is imperative that certain *fundamental* statements be included in the final decision. As noted previously, a failure to do so runs the risk of dampening the collaborative potential that exists for

¹⁶ Revised Alternate PD at 53.

Community Choice Aggregators to work in partnership with the Commission at the local level to implement effective Community Solar Green Tariff programs.

In light of this, the CCA Parties recommend that the following be reflected in the final decision:

- The Commission is obligated to foster fair competition between the IOUs and Community Choice Aggregators, while also ensuring that the Commission is developing programs that advance California’s environmental objectives.
- Community Choice Aggregators have expressed an interest in meaningfully participating in Community Solar Green Tariff programs.
- As local governmental entities, Community Choice Aggregators possess local attributes and advantages that uniquely qualify them for participation in successful Community Solar Green Tariff programs.
- Community Choice Aggregators and their customers should be allowed to participate in Community Solar Green Tariff programs in a manner that is non-discriminatory, competitively neutral and designed to achieve the goals of the Community Solar Green Tariff program.
- Applying non-discriminatory and competitively neutral requirements will likely necessitate modifications and adaptations to certain elements of the Community Solar Green Tariff program, including designating Community Choice Aggregators as the local sponsors and assigning to Community Choice Aggregators the operative functions under the program (*e.g.*, executing the power purchase agreement with the developer, establishing a marketing education and outreach budget, *etc.*).

As a general matter, implementation of the Community Solar Green Tariff programs will require additional delineation.¹⁷ Additional delineation will also be specifically necessary to apply non-discriminatory and competitively neutral requirements to CCA Community Solar Green Tariff programs. In this regard, the Commission can borrow from the procedure

¹⁷ In the previous version of the *Alternate Proposed Decision of Commissioner Guzman Aceves* (“APD”), this was reflected as follows: “We have specified many of the parameters and details of the program. However, there are a number of further details which must be delineated before the program can go into effect.” (APD at 104 [Section 7.6: Implementation Tariffs].)

previously applied in the context of DR programs. The CCA Parties recommend that the final decision set forth a process whereby the Energy Division conducts an additional workshop to develop input for these additional, CCA-related specifications. Following this workshop and related procedures, a decision from the Commission or a ruling from the Assigned Commissioner can be issued applying these requirements to Community Choice Aggregators that chose to administer Community Solar Green Tariff programs.

III. CONCLUSION

The CCA Parties thank the Commission for its consideration of the matters addressed in these opening comments.

Dated: June 11, 2018

Respectfully submitted,

/s/ Scott Blaising

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And on behalf of the CCA Parties

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

**Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment**

**R.17-06-026
(Filed June 29, 2017)**

**REPLY BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON TRACK 2 ISSUES**

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June 15, 2018

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List of Acronyms

A.	Application
A&G	Administrative and General
AB	Assembly Bill
AS	Ancillary Services
BCR	Bid Cost Recovery
BNI	Binding Notice of Intent
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CCGT	Combined Cycle Gas Turbine
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CT	Combustion Turbine
CTC	Competition Transition Charge
D.	Decision
DA	Direct Access
DG	Distributed Generation
DER	Distributed Energy Resources
DOE	US Department of Energy
DR	Demand Response
EE	Energy Efficiency
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
GHG	Greenhouse Gas
GRC	General Rate Case
IEPR	Integrated Energy Resource Plan
IOU	Investor Owned Utility
LCBF	Least Cost Best Fit
LSE	Load Serving Entity
LTTP	Long Term Procurement Plan
MCP	Market Clearing Price
MPB	Market Price Benchmark
NBC	Non Bypassable Charge
NPC	Nevada Power Company
NPV	Net Present Value
NREL	National Renewable Energy Laboratory

O&M	Operations and Maintenance
PAM	Portfolio Allocation Methodology
PCIA	Power Charge Indifference Adjustment
PDP	Peak Day Pricing
PG&E	Pacific Gas and Electric Company
POLR	Provider of Last Resort
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PUC	Public Utilities Code
PUCN	Public Utility Commission of Nevada
PX	Power Exchange
R.	Rulemaking
RA	Resource Adequacy
RBV	Resource Balance Year
RFO	Request for Offer
RMR	Reliability Must Run
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SPA	Staggered Portfolio Auction
T&D	Transmission and Distribution
UOG	Utility Owned Generation
URG	Utility Retained Generation

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

**REPLY BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON TRACK 2 ISSUES**

Pursuant to Rule 13.11 of the California Public Utilities Commission’s Rules of Practice and Procedure, the Amended Scoping Memo and Ruling of Assigned Commissioner issued March 2, 2018 in R.17-06-026, and Administrative Law Judge Roscow’s email directive of June 6, the California Community Choice Association (CalCCA) submits this reply brief.

I. INTRODUCTION AND EXECUTIVE SUMMARY

The solution adopted in this proceeding must resolve four key problems presented by the uneconomic resources accumulating in the Joint Utilities’ supply portfolios. It must:

1. Reduce the potential \$50 billion of uneconomic portfolio costs forecast to arise over the next 13 years;
2. Calculate and allocate these uneconomic costs in a way that fulfills the Commission’s statutory obligation to prevent cost shifts between bundled and departing load customers;
3. Reduce the growing mismatch between the Joint Utilities’ supply portfolios and their bundled load; and
4. End the “double procurement” occurring because non-utility load-serving entities (LSEs) are unable to access PCIA-eligible resources.

CalCCA's opening brief, amplified in this reply, explains why the two central competing visions -- (1) the Green Allocation Mechanism (GAM) and Portfolio Monetization Mechanism (PMM) supported by the Joint Utilities and ORA, and (2) the benchmark and sales approach advanced by The Utility Reform Network (TURN) -- cannot effectively solve the four key problems. These proposals fail in numerous ways:

- The Joint Utilities and TURN ignore the Legislature's directives on establishing departing load cost responsibility.
- The Joint Utilities and TURN rely on valuation principles that fail to capture the full range of products and attributes held in the utility portfolios.
- Both parties erroneously value the long-term contracts and assets held in the Joint Utilities' portfolios using prices intended to capture the value of only a limited supply of short-term products.
- The Joint Utilities' mechanism for redistributing portfolio resources -- the GAM -- is unlawful, undermines market valuation, maintains utility supply dominance despite declining load, and prevents CCAs from effectively planning their portfolios, procuring supply and managing risk.
- TURN's proposed alternatives for redistributing and valuing portfolio resources -- forward sales, voluntary retail seller subscription or auctions -- improve on the GAM/PMM and share similarities with CalCCA's proposed SPA but do not provide a sufficiently comprehensive solution to the structural problems.
- Neither party presents concrete options to reduce and slow the accumulation of uneconomic portfolio costs.
- The solutions proposed by the Joint Utilities and TURN cannot be implemented in the near term.

These proposals, if adopted, will understate portfolio value and overstate uneconomic costs, thereby overstating departing load cost responsibility and failing to prevent cost shifts between bundled and departing load customers.

CalCCA's phased proposal is the most effective approach to solving the four key problems. Correcting the Current Methodology (Corrected Methodology) eliminates the

existing cost shift from bundled to departing load customers and provides a simple, implementable transition to a durable long-term framework. The Staggered Portfolio Auction (SPA) will facilitate that long-term vision by redistributing portfolio resources on a voluntary basis to load-serving entities (LSEs), creating a market that establishes reliable values for the assets, and ensuring that entities that most value the resources obtain them. These proposals are complemented by measures aimed to reduce uneconomic portfolio costs through securitization, contract buydown, improved forecasting and improved portfolio management.

For these reasons, CalCCA asks the Commission to adopt the Corrected Methodology, the SPA and complementary cost reduction measures.

II. THE JOINT UTILITIES AND TURN IGNORE THE STATUTORY FRAMEWORK FOR ALLOCATING DEPARTING LOAD COST RESPONSIBILITY AND PREVENTING COST SHIFTS.

The Scoping Memo, as the Joint Utilities observe, established as its “overarching goal” in this proceeding “to prevent customer harm from impermissible cost shifting.”¹ The Joint Utilities also appropriately observe that the Commission’s obligation to prevent cost shifts arises from statute.² Despite this understanding, they blur the “bright line statutory mandate,”³ applying “indifference” as a general principle of equity, without regard to the specific cost responsibility and cost shift language chosen by the Legislature. TURN adopts a similar interpretation.⁴

¹ Joint Utilities Opening Brief at 6.

² *See, e.g., id.* at 4 (“California law prohibits cost shifts between customer groups as a consequence of departing load – in either direction.”); *see also Id.* at 19 (asserting a “statutory requirement that all customers remain indifferent to departing and migrating load.”).

³ *Id.* at 6; *see also id.* (“everyone must equitably share in the benefits and costs of procurement undertaken by the IOUs on their behalf”).

⁴ TURN Opening Brief at 4-5.

While the term “indifference” has been used by the Commission in prior decisions,⁵ it does not appear in any of the statutes aimed to prohibit “cost shifts.” “Indifference” is simply shorthand for the Legislature’s more detailed framework for assessing cost responsibility for departing load. Indifference cannot be reduced, however, to a generic form of equity, contrary to the contentions of the Joint Utilities. The Legislature has provided detailed guidance, and requires more than an allocation, as the Joint Utilities would have it, of “historical procurement costs,”⁶ using a tenet of “fundamental fairness”.⁷

In fact, the Joint Utilities’ application of this “fundamental fairness” doctrine has led to unfair results. For example, Mr. Wan explained that the utilities will not change their procurement or portfolio management strategy until departing load reaches between 10-20 percent of load.⁸ In other words, departure of a small amount of load like Marin Clean Energy’s (Marin’s) 2010 departure of 0.1 to 0.2 percent⁹ had no impact on PG&E’s procurement strategy.¹⁰ The costs of supply procured after PG&E became aware of Marin’s departure thus cannot reasonably be attributed to departing customers. Similarly, it fails the “fairness” test to allocate increasing uneconomic costs to a customer as prices decline if the utility could have sold that customer’s supply share at higher prices at the time of departure.¹¹

⁵ See, e.g., D.02-11-022; D.06-07-030; D.07-01-030.

⁶ See, e.g., Joint Utilities Opening Brief at 3, 6 and 44.

⁷ *Id.* at 6.

⁸ 1 Tr. 36:25-37:21 (Joint Utilities/Wan).

⁹ 5 Tr. 853:25- 854:4 (Joint Utilities/Lawlor).

¹⁰ 4 Tr. 823:14-19 (Joint Utilities/Lawlor).

¹¹ See CalCCA Opening Brief at 105.

Despite this lack of fairness and the detailed parameters given by the Legislature to define cost responsibility, the Joint Utilities and TURN construct their proposals based on a more general statutory provision enacted through SB 350. The section provides:

Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.¹²

The Joint Utilities boldly claim that theirs is “the only proposal that meets the overarching statutory requirement to prevent ‘any cost increases’ to remaining bundled service customers as a result of departing load.”¹³ TURN likewise focuses on the Legislature’s directive that bundled customers shall “not experience any cost increases” as a result of departing load.¹⁴

While CalCCA agrees that this statute is important and relevant, it cannot reasonably be read to render the Legislature’s more specific guidance on departing load costs as suddenly superfluous. The Legislature knew how to specify costs that must be included to avoid cost shifts. AB 1890 provided a very specific definition of the scope of costs to be included in transition costs, including the costs of then-existing utility-owned generation (Legacy UOG).¹⁵ AB 117, likewise, provided a detailed identification of the costs that must be recovered from CCA departing load to prevent cost shifts, including costs related to California Department of Water Resources (CDWR) obligations,¹⁶

¹² Cal. Pub. Util. Code § 366.3.

¹³ Joint Utilities Opening Brief at 6.

¹⁴ TURN Opening Brief at 4.

¹⁵ See Assembly Bill 1890 (Stats. 1996, ch. 854) (hereafter, AB 1890), § 840(f) (defining “Transition Costs”).

¹⁶ *Id.* §366.2(e).

business implementation costs¹⁷ and certain account balances.¹⁸ Relevant to this proceeding, the Legislature specifically identified the procurement costs that must be borne by CCA departing load to prevent cost shifts: the “estimated net unavoidable...purchase contract costs...attributable to”¹⁹ the departing load customer. The Legislature directed the Commission to reduce those costs by the “value of any benefits that remain with bundled service customers” in the utility portfolio.²⁰ The Legislature has taken no action to expressly augment these obligations in the context of CCA cost responsibility.

The Legislature’s next directive on cost shifts arose in SB 350, which specified a new, well-defined category of CCA departing load costs, procurement under the Integrated Resource Plan (IRP):

To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.²¹

SB 350 also included the language relied upon by the Scoping Memo and Joint Utilities, quoted above, prohibiting a “cost increase” to either bundled or departing load customers as a result of load departure.

¹⁷ Cal. Pub. Util. Code § 366.2(c)(17).

¹⁸ *Id.* § 366.2(f)(1).

¹⁹ Cal. Pub. Util. Code § 366.2(f)(2).

²⁰ Cal. Pub. Util. Code § 366.2(g).

²¹ Cal. Pub. Util. Code § 454.52(c)

The “cost increase” language of Section 366.3 must be harmonized with existing statutes and harmonized internally with other SB 350 provisions.²² Nothing in SB 350 suggests legislative intent to override the more specific directives of AB 117 or Section 454.52(c). Moreover, interpreting Section 366.3 as broad authority²³ to impose any and all utility categories of costs on departing load renders these more specific legislative directives surplusage, a result that must be avoided.²⁴ To harmonize the statute—internally and with other existing provisions—it must be read as a simplified restatement of the more specific guidance and, more importantly, clarification that cost shifts are prevented in both directions.

III. SCOPE OF PCIA ELIGIBLE COSTS

A. The Statutory Framework for CCA Cost Responsibility Excludes Legacy UOG Costs.

Most of the active parties in the rulemaking build their proposals on the assumption that Legacy UOG costs will continue to be recovered from nearly all departing load customers. The only class of customers exempted from these costs would be pre-2009 Direct Access customers.²⁵ CalCCA’s opening brief explained in great

²² *Cal. Mfrs. Assn. v. Pub. Util. Com.* (1979) 24 Cal.3d 836, 844, 157 Cal. Rptr. 676 (“Words must be construed in context, and statutes must be harmonized, both internally and with each other, to the extent possible” (citing *Moyer v. Workmen's Comp. Appeals Bd.* (1973) 10 Cal.3d 222, 230 [110 Cal. Rptr. 144, 514 P.2d 1224]; *Select Base Materials v. Board of Equal.*, *supra*, at p. 645; *Johnstone v. Richardson* (1951) 103 Cal. App.2d 41, 46 [229 P.2d 9])).

²³ While AB 117 provided the Commission with discretion to determine costs, that discretion was set in the context of a specific cost category: “the share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission....” Cal. Pub. Util. Code § 366.2(f)(2).

²⁴ *Cal. Mfrs. Assn.* at 844 (citing *Fields v. Eu* (1976) 18 Cal.3d 322, 328 [134 Cal. Rptr. 367, 556 P.2d 729]; *Sanchez v. South Hoover Hospital* (1976) 18 Cal.3d 93, 98 [132 Cal. Rptr. 657, 553 P.2d 1129]; *Stanley v. Justice Court* (1976) 55 Cal. App.3d 244, 253 [127 Cal. Rptr. 532]; *Watkins v. Real Estate Commissioner* (1960) 182 Cal. App.2d 397, 400 [6 Cal. Rptr. 191]).

²⁵ AREM/DACC Opening Brief at 5.

detail that under applicable statutes, Legacy UOG costs cannot be allocated to CCA departing load customers – a point that has not to this point been legally challenged.²⁶ And to exempt pre-2009 DA customers while imposing these costs on CCA customers would result in undue discrimination.²⁷ Nothing in the parties’ opening briefs alters these conclusions.

B. No Reasonable Grounds Exist to Modify the 10-Year Limitation on Fossil Resource Cost Recovery.

The Joint Utilities seek to lift the 10-year cost recovery limitation for post-2002 fossil generation resources.²⁸ CalCCA’s opening brief argues that nothing has changed since the limitation was imposed beginning in 2003 to warrant the limitation’s removal.²⁹ Again, nothing in the parties’ opening briefs alters CalCCA’s conclusion.

As CalCCA has noted previously, the Commission created a very limited exception from this limitation, which was to be applied on a case-by-case basis in the *application* for approval of the resources.³⁰ The Commission expected the utilities to manage their portfolios in a way that would address the presence of these resources.³¹ Despite voicing repeated concerns that the IOUs are likely to lose 85% or more of their bundled load, the Joint Utilities spent considerable time and effort in this proceeding attempting to justify the retention of a generation portfolio that could be 500% or more in

²⁶ CalCCA Opening Brief at 29-36.

²⁷ *Id.*

²⁸ Joint Utilities Opening Brief at 24-25.

²⁹ CalCCA Opening Brief at 37-42.

³⁰ *Id.* at 38.

³¹ *See, e.g.*, D.08-09-012 at 54-55.

excess of their needs.³² The Joint Utilities' seeming inability to tailor a portfolio to reasonable expectations over the past decade³³ is not a sufficient reason to permit continued cost recovery.

IV. PORTFOLIO VALUATION METHODOLOGIES

CalCCA replies to two of the parties' contentions regarding portfolio valuation:

- The dubious and illogical assertion that there is no inherent long-term value in the Joint Utilities' portfolios of long-term supply resources, a position which is undermined by the Joint Utilities' own witnesses and has already been rejected by the Commission; and
- The unsupportable contention that the only way to attain a reasonable valuation of the Joint Utilities' portfolios is through a "receipt" from the CAISO from actual sales.

Neither of these contentions is true. They highlight a fundamentally flawed viewpoint on markets and asset values, as well as an abdication of the Joint Utilities' responsibility to maximize portfolio value on behalf of all customers. They also presage devaluation of the Joint Utilities' supply portfolios to justify the flawed GAM/PMM proposal over better alternatives and impose higher stranded cost charges on departing load customers. The Commission, as it has before, should reject these unfounded assertions. Instead, it should focus on implementing approaches, such as CalCCA's proposal, that both recognize and work to extract the highest long-term value of the Joint Utilities portfolios for the benefit of all customers.

³² Under the scenario often cited in this proceeding, in which 85% of load departs utility service, and therefore in which up to 85% of the Joint Utilities pre-departure supply is excess to their bundled load of 15% ($85\% / 15\% = 567\%$).

³³ See CalCCA Opening Brief at 97-115.

A. Long-Term Value for a Wider Range of Products and Attributes Must Be Used to Value the Joint Utilities' Portfolios.

CalCCA proposes the use of long-term values for a wider range of products and attributes to adequately reflect the characteristics of the Joint Utilities' portfolios of long-term resources.³⁴ Ratepayer advocates do not all agree, although UCAN and POC share similar views, rejecting the use of value measures that do not capture the full value of portfolio resources. ORA, while not fully committing, acknowledges that “[i]t is possible that there is additional value for long term RA and RPS products not reflected in the short-term market.”³⁵ TURN, based on the same faulty assumptions used by the Joint Utilities, does not support the recognition of additional values in the portfolio.

UCAN, in stark contrast to TURN, recognizes “the value stack for long-run PPAs and utility assets must reflect the full set of values these units provide, which are traditionally recognized in planning and procuring for the future....”³⁶ It identifies numerous attributes of value in the utility portfolios³⁷ that go far beyond the scope of attributes valued by the Current Methodology and even the benchmarks recommended by CalCCA. UCAN also recognizes the need for long-term value measures in valuing the utility portfolios, stating:

Comparable valuation matches the time frames of services/products and market referents or metrics. Accordingly long run PPAs should be valued in comparison to similar long run metrics, and certainly not compared to short-run metrics.³⁸

³⁴ See generally CalCCA Opening Brief at 42-52.

³⁵ ORA Opening Brief at 10.

³⁶ *Id.*

³⁷ *Id.* at 17-18.

³⁸ UCAN Opening Brief at 23.

Though admitting that such may be challenging to measure, UCAN contends that proper valuation must incorporate not only at intrinsic resource value, but extrinsic (long-term) value,³⁹ including hedge value and the value of optionality.⁴⁰ It contends:

There is always a price premium paid to reduce long-term uncertainty, which is a major part of the hedge value inherent in bilateral contracts; spot (physical) prices have little if any hedge value, so would systematically understate bilateral contract value.⁴¹

UCAN concludes that “[w]ith extrinsic value added to intrinsic value, the portfolio value is substantially increased.”⁴²

In its Opening Brief section entitled “Best-Practice Valuation Metrics and Appropriate Time Frames – a Calibration to Market Principles,” UCAN spells out a set of "market principles" which are perhaps better described as cost evaluation perspectives that differ between the utilities and the CCAs.⁴³ But according to UCAN’s “market principles,” the utilities could maximize their asset valuation through a combination of better portfolio management and transacting more vigorously with CCAs. CalCCA's SPA proposal would achieve these objectives the most directly among the proposals.

POC likewise aligns with CalCCA’s view on portfolio valuation. POC observes that “bundled load continues to extract the full value of long-term contracts retained in the utilities’ portfolios, while departing load is credited only the more limited value associated with short-term sale of resources held under those contracts.”⁴⁴ Like UCAN, POC proposes that any valuation methodology should “ensure that departing load is

³⁹ *Id.* at 27-28.

⁴⁰ *Id.*

⁴¹ *Id.* at 20.

⁴² *Id.* at 28.

⁴³ *Id.* at 4.

⁴⁴ POC Opening Brief at 26.

credited for hedging and optionality values associated with long-term contracts as well as premiums associated with delivery of energy from greenhouse gas free resources.”⁴⁵

The Joint Utilities oppose valuing additional attributes or placing a long-term value on the attributes in the portfolio. The Joint Utilities contend that there is no long-term value that is not already captured by “short-term sales of the underlying energy.”⁴⁶ They assert that “CalCCA’s proposal turns basic economic theory on its head, agreeing with the Coalition of California Utility Employees (CUE) that to assume that there is long-term value is “a basic economic error.”⁴⁷ They also “...agree with the common-sense conclusion expressed by TURN and CUE that the value of an asset that an entity no longer needs is determined by what market participants are willing to pay for it.”⁴⁸ (Interestingly enough, the Joint Utilities are not proposing to dispose of or retire permanently assets “that an entity no longer needs”—apparently those assets still have value to the Joint Utilities.)

If an asset’s value is determined by the willingness of market participants to pay for it, why not offer up the asset to the market on a long-term basis as proposed by CalCCA, rather than liquidate that asset in short-term markets as proposed by the Joint Utilities? If there is no long-term value in long-term contracts, why doesn’t the

⁴⁵ *Id.*

⁴⁶ Joint Utilities Opening Brief at 33.

⁴⁷ *Id.* at 36. Both CUE and the Joint Utilities selectively misquote and mischaracterize CalCCA’s testimony regarding the relationship between resource cost and market value. Following is the full quote to put CalCCA’s position in proper context: “As explained in Chapter 2B, §II, the current capacity benchmark reflects only the annual unavoidable costs of maintaining a combustion turbine available to provide capacity – a short-term value measure. The value placed on capacity in the long run, as demonstrated by Commission-adopted capacity values, must reflect all costs of that resource, including the development and construction costs.” Exh. CalCCA-1 at 2A-3.

⁴⁸ Joint Utilities Opening Brief at 33.

Commission simply allow the utilities to rely on the spot market for all of their needs, as they did in the late 1990s? Relying solely on the spot market would risk inadequate supply, price volatility and increased costs and a failure to comply with RPS and RA requirements.⁴⁹ Moreover, the Commission itself has already expressly rejected proposals by the Joint Utilities in other contexts to use short-term prices to determine the value of their RPS portfolios in favor of long-term valuation metrics.⁵⁰

In fact, the Joint Utilities admit to long-term portfolio value.

- Mr. Wan stated that it was appropriate to use a 10-year forward price curve to value a 10-year asset.⁵¹
- Mr. Cushnie admitted that long-term RPS contracts could be devalued if traded in the short-term market as an unbundled REC.⁵²
- Mr. Wan admitted that optionality (which includes the hedge properties of long-term contracts) has value.⁵³
- The IOUs maintain hedge policies⁵⁴ and hedge to “stabilize price volatility.”⁵⁵
- PG&E maintains hedge limits with upper and lower boundaries for both energy and RA,⁵⁶ meaning a specified percentage of “bundled load is covered with existing resources or contracts.”⁵⁷
- The Joint Utilities’ opening brief admits that a “natural hedge” exists in a fixed price contract.⁵⁸

⁴⁹ Exh. CalCCA-1 at 2B-4-5.
⁵⁰ CalCCA Opening Brief at 48.
⁵¹ 1 Tr. 34:16-23 (Joint Utilities/Wan).
⁵² 2 Tr. 255:6-15 (Joint Utilities/Cushnie).
⁵³ 1 Tr. 60:6-21 (Joint Utilities/Wan).
⁵⁴ 1 Tr. 135:26-28 (Wan/Joint Utilities/Wan).
⁵⁵ 1 Tr. 48:25-27 (Wan/Joint Utilities/Wan).
⁵⁶ *See generally* 1 Tr. 177:10-12 (Joint Utilities/Lawlor/Confidential).
⁵⁷ 1 Tr. 164:17-25 (Joint Utilities/Lawlor/Confidential).
⁵⁸ Joint Utilities Opening Brief at 37-38.

- While the Joint Utilities challenged the use of the current Green Adder, a long-term value measure, their challenge was not based on the long-term nature of the measure.⁵⁹

In addition, PG&E's own portfolio management document approved by the Commission explicitly seeks to justify continuing to hold existing RPS power purchase agreements (PPAs) without liquidating in spite of falling short term market prices.⁶⁰ None of these statements and actions makes sense if the utilities believed that the *entire* value of their physical generation assets was captured solely in short-run market indicators.

The Joint Utilities argue that the appropriate method of valuing these assets is the CAISO spot energy market, the short-term RA market and the short-term REC market. At the same time, they are striving to hold onto and control these long-lived assets in the utility portfolio, doling out limited attributes into short-term markets, without conveying long-term value to the recipient. The utilities should be glad to hand over complete control and responsibility of those assets to CCAs for the spot market prices if they believed their own claims. Yet instead we see offers that are for highly constrained products for limited duration making little or no effort to flatten their long-term surplus supply positions.⁶¹ The Joint Utilities clearly value something in these assets they continue to hold, and there is an obvious value to these assets outside the short-term spot market prices.

CalCCA agrees that real market derived transaction prices are the preferred method of valuing the IOU portfolios, but only under the conditions identified in Section B, below. Consistent with that view, CalCCA proposes to require the utilities

⁵⁹ Exh. IOU-1 at 2-15 to 2-18.

⁶⁰ 5 Tr. 901:10-902:1 (CalCCA/McCann) (quoting PG&E's draft renewable energy procurement plan at page 19).

⁶¹ See 4 Tr. 837: 22-26 (Joint Utilities/Lawlor).

sell the portfolio contents in a market will be capable of recognizing and pricing all attributes and characteristics of each asset or contract.

B. “Receipts” for Product or Attribute Sales Do Not Fairly Represent the Value of the Joint Utilities’ Portfolios Under Current Conditions.

Calculating the uneconomic costs that must be shouldered by bundled and departing load customers requires a comparison of portfolio costs and portfolio value. CalCCA rejects the premise that the use of “receipts” is the only approach to the valuation of long-lived assets. “Receipts” may be a reasonable valuation measure, however, under three conditions: (1) the receipts are used only to value products actually sold; (2) the products are sold in a manner that maximizes their value; and (3) the market in which the receipt is produced fully reflects the value of the resource. CalCCA contends that these conditions are not and will not be present unless and until a comprehensive solution aimed to *create* these conditions, such as CalCCA’s Staggered Portfolio Auction (SPA), is implemented. Moreover, adoption of the GAM/PMM, by circumventing market valuation, would ensure that these conditions never occur.

A receipt for a product sold from the utility’s portfolio would logically, under most circumstances, reflect the value of *that product*. The receipt could not generally be used, however, to value *other* portfolio products: a receipt for sale of one-month of RA would not fairly represent the long-term value of capacity, as the Joint Utilities acknowledge.⁶² A single month of RA compliance is simply *not the same product* as a long-term right to control capacity. Likewise, as the Commission observed in the 2017 Padilla Report, the price for sale of a small volume of product cannot reasonably be used to value a large unsold volume of the same product if it is unlikely that the total volume

⁶² See CalCCA Opening Brief at 75.

could be replaced at that price.⁶³

In addition, for a receipt to be used as a value measure, the product must be sold in a way that maximizes value. For example, the price a utility will get in the market for the sale of a product will depend upon when the product is sold, the length of the term of the product and other terms and conditions.⁶⁴ A product could easily be sold in a way that the receipt *does not* fairly represent the product's value.

Finally, a receipt for sale of a product only represents the product's value if there *is an appropriate market* for that product.⁶⁵ The Joint Utilities have acknowledged that “a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”⁶⁶ In other words, there is currently not a market that will produce a receipt that can be used to reasonably represent the value of capacity.

The Joint Utilities' GAM/PMM proposal does not create an environment in which a receipt from a sale into the market reasonably represents the value of all of the products in the portfolio—the Joint Utilities propose to bypass markets entirely for RPS attributes and the majority of RA attributes. A large portion of capacity needed for an LSE to meet its RA requirement—up to 44 percent⁶⁷—would be allocated through the Cost Allocation Mechanism (CAM) and GAM combined, and would, therefore, reduce the amount of

⁶³ CalCCA-106, *The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016*, May 1, 2017, at 12 (short-run avoided costs was not a reasonable value measure for RPS resources because “it seems unlikely that the large IOUs would be able to procure 20% or more of their portfolios accounted for by the RPS program under short-term contracts”).

⁶⁴ CalCCA Opening Brief at 114.

⁶⁵ See Exh. CalCCA-1 at 2B-4.

⁶⁶ Exh. IOU-1 at 5-9.

⁶⁷ See CalCCA Opening Brief at 85.

capacity that is actually traded in and valued by the market.⁶⁸ Likewise, the GAM would remove the vast majority of RECs from market trading and valuation. Assuming the program could be implemented, nearly all of the RECs needed to meet an LSE's 33 percent RPS requirement would be allocated, rather than sold in a market.⁶⁹ Moreover, a large percentage of the RECs allocated through the GAM could not be sold by the receiving LSE without a substantial loss of value.⁷⁰ The GAM/PMM would make sure that receipts for RA or RECs *do not* fairly represent the value of the underlying products and would prevent the development of markets for these products.

ORA⁷¹ and TURN⁷² similarly assert that portfolio valuation should only be based on “realized” market values. Ignoring the fact that most generation assets are not “sold” into the market, but rather are scheduled to meet the LSE's load, this principle has a bizarre implication. As the market evolves to eliminate fossil fuels through compliance with state law, reliability requirements will increasingly be met by distributed local resources. If the CAISO energy market clearing price (MCP) falls to \$0 (or even becomes negative, which is already occurring in a number of hours), the utilities sign no new RPS-eligible PPAs, and a large capacity surplus drives short-term RA prices to zero,⁷³ then the portfolio valuation would be \$0 under the premise put forward by ORA and TURN. Could anyone seriously believe that the utilities' portfolios, while still providing services to their bundled customers, would have no value? It becomes obvious that the value of the utilities' generating portfolios exceeds any short-run metrics.

⁶⁸

Id.

⁶⁹

See id. at 83-84.

⁷⁰

2 Tr. 367: 6-10.

⁷¹

ORA Opening Brief at 8.

⁷²

TURN Opening Brief at 5.

⁷³

Id. at 8. TURN asserts that the current surplus capacity has a value of zero.

Otherwise, ORA and TURN should be contending that the utilities' assets are no longer used and useful, and should be retired immediately.

The SPA creates conditions under which receipts for product sale could be used to value any residual portfolio. The SPA would sell products, to the extent possible, that mirror the products in the utility portfolio in term and other key terms and conditions.⁷⁴ It would also offer for sale over time all RPS and GHG-free contracts and products, rather than just the product surplus. Taking this approach provides the opportunity to fully realize the value of the portfolio products and attributes.⁷⁵ The SPA, by placing even the Joint Utilities in a position to purchase from the auction for bundled load, ensures the development of a deeper, more liquid market that will more reasonably reflect product value.⁷⁶

C. No Value Measure Will Be Perfect, and Commission-Approved Administrative Benchmarks Provide Reasonable Proxies for Portfolio Valuation Pending Implementation of the SPA.

The Joint Utilities assert that administratively determined benchmarks should not be used to value their portfolios.⁷⁷ They argue:

Administratively-determined benchmarks not trued up to actual market transactions and portfolio volumes can never satisfy the statutory requirement that all customers remain indifferent to departing and migrating load. This is because administratively-set benchmarks, by definition, rely on incomplete information about markets and will therefore deviate, often substantially, from actual market outcomes.⁷⁸

⁷⁴ Exh. CalCCA-1 at 4-4: 1-3.

⁷⁵ CalCCA Opening Brief at 75.

⁷⁶ *Id.* at 50-51.

⁷⁷ Joint Utilities Opening Brief at 23.

⁷⁸ *Id.* at 9.

They further argue that no party proposed RA or RPS benchmarks that accurately reflect the market value of those resources.⁷⁹

CalCCA acknowledges that no benchmark for departing load responsibility will be perfect. Dr. Barkovich summarized the problem the Commission faces in this proceeding:

My conclusion is there's room for improvement definitely, but that there is no perfect solution that makes everybody perfectly indifferent. There are too many variables here.⁸⁰

It appears the Legislature was aware of this challenge and did not expect precision. AB 117 placed cost responsibility on CCA departing load for “*estimated*” net unavoidable costs.⁸¹ The Commission is thus left to choose a reasonably representative set of metrics to value the Joint Utilities’ portfolios.

The Joint Utilities claim administratively determined benchmarks cannot meet the statutory indifference requirement, characterizing those benchmarks as “imprecise and risk-fraught.”⁸² As CalCCA explained in its opening brief, the Commission has extensive experience in developing administrative values and relies on these values for critical decisionmaking.⁸³ Moreover, the same characterization – imprecise and risk-fraught – could be applied to the Joint Utilities’ reliance on short-term market values to calculate the cost shift and cost responsibility under the PMM. As discussed in Section IV, the “market” values the Joint Utilities embrace are incapable of measuring portfolio value under current conditions.

⁷⁹ See generally *id.* at 12-16, 17-21.

⁸⁰ 3 Tr. 519:18-22 (CLECA/ Barkovich).

⁸¹ Cal. Pub. Util. Code § 366.2(f)(2).

⁸² Joint Utilities Opening Brief at 88.

⁸³ CalCCA Opening Brief at 42-43.

Under these circumstances, a true-up would serve little purpose. The Joint Utilities acknowledge that a true-up of REC prices would be challenging.⁸⁴ For RA, however, it proposes to true-up an unrepresentative RA forecast “market” value with another unrepresentative “market” value.⁸⁵ Moreover, while there may be a better foundation for true-up of energy revenues, testimony shows no meaningful impact of a true-up over the past five years. Mark Fulmer, on behalf of AReM/DACC, concluded that “[e]xcept for 2015, the two MPB and CAISO averages have been within ~15% of each other. 2015 is an outlier, with the CAISO prices falling from 2014 by over 30%.”⁸⁶ The MPB was lower than actual prices in 2013 and 2014 and higher in 2015-16 and roughly the same in 2017.⁸⁷ These differences are insufficient to justify the uncertainty and potential volatility a true up of energy revenues could bring.

There is no easy answer, and the Commission must reject the Joint Utilities’ attempts to oversimplify the indifference calculation. It must determine, for each product and attribute in the Joint Utilities’ portfolios, the most reasonably representative value under current conditions, with an eye toward a more comprehensive solution.

V. PROPOSED ALLOCATION METHODOLOGIES

A. The Joint Utilities’ GAM/PMM is Unlawful and Unsound Policy

CalCCA’s opening brief concluded that the GAM/PMM is unlawful because it forces products into CCA portfolios,⁸⁸ unreasonably maintains utility dominance in the face of

⁸⁴ See Joint Utilities Opening Brief at 84-85.

⁸⁵ Exh. AReM/DACC-1, Prepared Direct Testimony of Mark Fulmer at 12, Figure 1.

⁸⁶ *Id.* at 11.

⁸⁷ *Id.* Figure 1 at 12.

⁸⁸ CalCCA Opening Brief at 81-86.

declining bundled load⁸⁹ and devalues portfolio resources.⁹⁰ CalCCA further concluded that the GAM/PMM is not a suitable long-term solution, yet is too complex to implement in the near term.⁹¹ The Joint Utilities’ Opening Brief, along with viewpoints expressed by TURN, CLECA and others, only reinforce these conclusions.

The Joint Utilities argue that the GAM/PMM “ensures complete customer indifference, because all customers pay for the costs and receive the benefits of the historical resources procured on their behalf...”⁹² While the GAM/PMM may fulfill the Joint Utilities’ fluid, one-way vision of indifference, it does not suit the framework enacted by the Legislature. The GAM/PMM, through mandatory product allocation, impairs a CCA’s statutory right “to be solely responsible for all generation procurement activities on behalf of” the CCA’s customers.⁹³ The Joint Utilities’ observation that the products being allocated were procured when the CCA’s customers were bundled customers⁹⁴ does not alter this conclusion. The forced allocation forecloses autonomous procurement by the CCA to the extent of the allocation.

The GAM/PMM also infringes on a CCA’s procurement of RA and RPS for its customers. It would foreclose procurement (and cause overprocurement) for RPS resources. For example, on the SCE system the allocation will account for vast majority of resources necessary to meet a CCA’s 2020 requirement.⁹⁵ The Joint Utilities’

⁸⁹ *Id.* at 86-88.

⁹⁰ *Id.* at 88-94.

⁹¹ *Id.* at 94-97.

⁹² Joint Utilities Opening Brief at 43.

⁹³ Cal. Pub. Util. Code § 366.2(a)(5).

⁹⁴ Joint Utilities Opening Brief at 5.

⁹⁵ *See* CalCCA Opening Brief at 83.

proposed combined CAM and GAM allocation would also approach half of a CCA's obligation.⁹⁶

There are limited exceptions to the mandate that CCAs be "solely responsible" for their procurement, but the exceptions themselves must be mandated.⁹⁷ Thus, the GAM allocation is not supported by statute.

Other parties reach similar conclusions.⁹⁸ TURN's criticisms of the GAM/PMM focus on critical implementation problems. The GAM/PMM would require the Commission, contrary to prior decisions, to ignore the unbundling of RECs from the underlying long-term resources.⁹⁹ Effectively, in order to preserve the compliance value of the allocation, the Commission must magically reclassify unbundled RECs as bundled RECs. The Commission must also somehow deem the unbundled RECs so allocated as the *recipient LSE's* "contracts of 10 years or more in duration" or "its ownership or ownership agreements" for long-term resources to maintain the RECs' compliance value under Section 399.13(b).¹⁰⁰ Even if the Commission could transform the products by proclamation, the Joint Utilities acknowledge that the allocated RECs would not retain the long-term, bundled characteristics if the recipient LSE traded them in the market.¹⁰¹ Under these circumstances, as Mr. Cushnie acknowledged, the underlying resource could

⁹⁶ *Id.* at 85.

⁹⁷ Cal. Pub. Util. Code § 366.2(g).

⁹⁸ See AReM/DACC Opening Brief at 26 ([T]he IOU allocation of RA and RPS attributes based on the proposed GAM threatens to frustrate all that careful planning by informing an ESP or CCA long after its portfolio has been designed and implemented that certain of its renewable and RA acquisitions were unnecessary and/or superfluous); LACCE/Coachella/WRCOG Opening Brief at 4-5; Shell Opening Brief at 11.

⁹⁹ TURN Opening Brief at 19-20.

¹⁰⁰ Cal. Pub. Util. Code §399.13(b); see TURN Opening Brief at 20-21.

¹⁰¹ 2 Tr. 367: 3-10. (Cushnie/Joint Utilities).

be devalued.¹⁰² In other words, the “market value” of the key attributes would be stripped from the asset for the recipient LSE, and the value of those attributes would redound back to bundled customers. Costs would be shifted from bundled to departed customers, contrary to state law.

TURN correctly observes that the CEC’s Power Source Disclosure Program “is not currently configured to address the possible complications resulting from this approach” thus presenting “another wrinkle.”¹⁰³ CalCCA agrees. The Joint Utilities have not explained how the GAM allocation would be treated under this program or what process would be required to effectuate the program.

Similarly, the Joint Utilities have failed to explain how the GAM would interact with the Clean Net Short (CNS) methodology adopted in R.16-02-007.¹⁰⁴ Under the CNS, GHG emissions are attributed to each LSE based on the energy it has contracted to serve its load. If a CCA procures a zero-emitting resource on a bundled basis, the CCA will get GHG credit under the CNS for each hour in which the resource produces electricity. It appears that under the GAM, however, the CCA would receive the RECs, but brown energy would be attributed during the hours when the REC is created because the utility, not the CCA, would retain the associated energy.¹⁰⁵ Moreover, forcing the RECs into the CCA’s portfolio without the associated energy would foreclose the CCA from buying bundled products that would provide both RECs and zero emitting energy.

¹⁰² *See id.*

¹⁰³ TURN Opening Brief at 23.

¹⁰⁴ Administrative Law Judge’s Ruling Finalizing Greenhouse Gas Emissions Accounting Methods, Load Forecasts and Greenhouse Gas Benchmarks for Individual Integrated Resource Plan Filings, R.16-07-002, May 25, 2018.

¹⁰⁵ *See* Joint Utilities Opening Brief at 43.

The CNS is a key policy measure in the state’s efforts to reduce GHG emissions in the electricity sector, and the GAM would undermine the operation and success of the CNS.

Several other parties raise concerns about the GAM/PMM. Though CLECA provides only very limited analysis, it concludes that GAM/PMM risks understating capacity value.¹⁰⁶ UCAN appropriate points out that the GAM/PMM “do not capture the long-run attributes of bilateral contracts....”¹⁰⁷ Commercial Energy opposes the GAM/PMM, among other reasons, because:

[T]he lack of price transparency for PCIA-eligible IOU resources before they are allocated or sold through the GAM or PMM will perpetuate the greater uncertainty and risk for LSEs that currently permeates the PCIA process. Only the IOUs truly know the value of their resources; under the GAM/PMM the LSEs would continue to be unable to value the assets with actual market data.¹⁰⁸

Commercial Energy also points out that the under the Joint Utilities’ proposal, “there is no predictability and LSEs will be deprived of a realistic planning horizon for both their own procurement needs and the PCIA cost responsibility....”¹⁰⁹ Finally, Southern California CCAs suggest that GAM/PMM would result in a “substantial disruption of CCA formation, implementation and procurement....”¹¹⁰

B. TURN’s Proposals Do Not Provide a Viable Solution.

TURN, like CalCCA, offers both a near term and a longer term solution. Its near-term solution, which retains and modifies the Current Methodology, would perpetuate the existing cost shift from bundled to departing load customers. Moreover, it is based on the

¹⁰⁶ CLECA Opening Brief at 14-16.

¹⁰⁷ UCAN Opening Brief at 31.

¹⁰⁸ Commercial Energy Opening Brief at 34.

¹⁰⁹ *Id.*

¹¹⁰ LACCE/Coachella/WRCOG Opening Brief at 6.

unsupportable “receipt” method of portfolio valuation embraced by the utilities.¹¹¹ As discussed above, TURN’s proposal could easily lead to the portfolios having no “value” contrary to the reality that these assets continue to serve (bundled) customers.

TURN’s longer-term solutions are headed in the right direction. They “are focused on providing opportunities for LSEs to acquire *valuable* products from the utility portfolios that can be used to serve their retail customers,” avoiding involuntary utility allocations of “tradable attributes that have dubious real-world value.”¹¹² While conceptually CalCCA and TURN appear to align around the longer term goal of making sure the Joint Utilities sell “valuable” product, these parties do not agree on a solution. None of TURN’s three alternatives—forward sales, retail seller subscription and auction—can provide the liquidity needed to derive true market values, which requires full participation by *all* market players including the Joint Utilities. CalCCA’s proposals, which contemplate a much broader sale process, remedy these shortcomings.

C. TURN’s Near-Term Modification of the Current Methodology Will Increase the Cost Shift from Bundled to Departing Load Customers

In the near term, TURN proposes to retain and modify the Current Methodology,¹¹³ proposing changes to the RA values and the Green Adder values used in the calculation. While an element of TURN’s Green Adder modification—a broadening of data used to establish the Green Adder—merits consideration, the remaining proposals will only increase the cost shift from bundled to departing load.

¹¹¹ 5 Tr. 1078:22-1079:5 (TURN/Woodruff).

¹¹² TURN Opening Brief at 25-26 (emphasis supplied).

¹¹³ TURN Opening Brief at 2.

1. Capacity Value

TURN's proposal to value RA based on the Commission's annual Resource Adequacy Report developed by the Energy Division also fails to acknowledge long-term capacity value. As an initial matter, TURN relies on a dated RA Report that reflects 2016 recorded transactions. In addition, the reported prices value short-term RA sales, which are not the same product as the long-term capacity embedded in the portfolio. Moreover, TURN's proposal ignores:

- The insufficiency of the capacity market to reflect the “full value” of the portfolio resources, as the Joint Utilities acknowledge;¹¹⁴
- The limited scope of products reflected in the RA Report, ignoring the value of bilateral contracts, the CAM allocation, the CAISO CPM and the CAISO RMR mechanisms; and¹¹⁵
- The lack of depth in the report, which represents only 19.7 percent of 2016 RA; most RA is “procured via long-term PPAs rather than via short-term transactions.”¹¹⁶

While the RA Report may be useful for some purpose, it should not be used to value the capacity of long-term utility resources.

TURN exacerbates its RA undervaluation by proposing to assign “a zero or *de minimis* price for capacity expected to remain unsold.”¹¹⁷ This proposal, again, ignores the longer term value of the capacity, ignores the possibility that the utility may retain RA as a hedge to protect bundled load and prevent non-compliance, and ignores the fact that the timing and manner of selling RA will influence the utility's ability to sell the product

¹¹⁴ Exh. IOU-1 at 5-9:21-23 (“Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”).

¹¹⁵ Exh. CalCCA-3 2B-3:12-17.

¹¹⁶ *Id.* at 2B-3:17-21.

¹¹⁷ TURN Opening Brief at 2.

and the price obtained.¹¹⁸ As CalCCA’s opening brief pointed out “waiting until the last minute to make short-term RA sales inevitably leads to the realization of little or no value because the value of RA declines precipitously at (or just before) the deadlines occur.”¹¹⁹

TURN boldly suggests that “[t]here is no dispute that [the RA Report] accurately reflects recent and current conditions for these RA products and illustrates the expected prices that would be paid by any LSE seeking to obtain the product from the IOUs.”¹²⁰ CalCCA respectfully disagrees. While the RA Report prices may reflect the prices for a limited subset of RA compliance instruments unrelated to physical assets, procured on a short-term basis, the products are not the same product that is held in the utility portfolio. Clearly, a different value measure is required.

2. Green Adder

TURN, like most other parties, proposes to remove the DOE component of the Green Adder,¹²¹ replacing it with data gathered from all LSEs. All LSEs, presumably including CCAs, would “submit (under seal) price, volume and quantity data for purchases and sales of renewable energy....”¹²² In addition, TURN would change the measurement window, using only transactions “occurring in the prior year that include deliveries in the forecast year.”¹²³ This is a change from the currently methodology, which examines prices for “newly delivering” contracts in the forecast year, regardless of

¹¹⁸ See CalCCA Opening Brief at 107-109; see 1 Tr. 67:7-21 (Joint Utilities/Wan).

¹¹⁹ *Id.*

¹²⁰ TURN Opening Brief at 8.

¹²¹ *Id.*

¹²² *Id.*

¹²³ *Id.*

execution date. TURN also proposes an annual true up “to reconcile the forecast and actual sales prices and volumes.”¹²⁴

Broadening the scope of data used to calculate the Green Adder may be a reasonable approach, but only under certain conditions. First, CalCCA proposes that CCAs be permitted to aggregate RPS data for use by Commission staff to avoid unnecessary disclosure of transaction detail. A common template and instructions could be developed through a workshop that would accommodate this approach. Second, any use of non-utility contract prices should be for the procurement of power from new projects (not existing projects) with contract terms that are commensurate with the long-lived resources that are being valued in the PCIA-eligible portfolios (*i.e.*, no use of short-term trades from existing projects). Third, the prices being gathered and reported should not be limited to new transactions just in the past year, as TURN proposes. To ensure a large enough data set, CalCCA proposes the inclusion of contracts executed in the past five years for resources that will be newly delivering in the forecast year. Indeed, aggregating CCA procurement costs by year would highlight what CCAs spent – and what IOUs could have earned had they disposed of unneeded resources at that time. If this approach were considered the prices should be weighted by volume, and it should be recognized that the timing (*e.g.*, year) and duration (contract length) impact price. Fourth, this approach should be a transition approach, limited in time until SPA is implemented, at which point the auction prices would be used to establish any needed benchmarks.

¹²⁴

Id.

CalCCA opposes the other two aspects of TURN's proposal: changes in the measurement window and the true-up of forecast to actual data. TURN proposes to rely on contracts executed in the past year that will begin delivering in the forecast year – a position for which TURN provides little explanation. TURN's proposal would substantially reduce the data set and drive the Green Adder toward short-term prices, which reflect annual regulatory compliance requirements rather than asset values. In fact, new contracts for physical assets would be almost entirely ignored since few generation resources can be built on such short turnaround. As explained in CalCCA's testimony, the Current Methodology's reliance on the prices of "newly delivering" contracts remains sound.¹²⁵ Newly delivering contracts reflect the price that would have to be paid to acquire a physical generating resource that is capable of delivering in the forecast window, not just a compliance showing. Second, the true-up approach for RPS unnecessarily undermines certainty and predictability, and reflects another extension of the "receipt" approach. The suggestion that there would be a value significant enough to offset the resulting uncertainty is untested.

3. TURN's Three Alternatives Cannot Reasonably Be Implemented Any More Quickly than CalCCA's More Comprehensive Solution

TURN's opening brief covers the waterfront of voluntary options, including forward sales by the utilities, retail seller subscription and an auction of utility resources. While interesting, these concepts cannot be implemented in the near term. In 2018 the Joint Utilities began, for the first time, to experiment with forward sales (although

¹²⁵ Exh. CalCCA-3 at 2B-11:3 – 2B-12:3.

nothing has prevented them from undertaking such sales in the past).¹²⁶ In fact, to date, the utilities have not sold forward contracts of any significant length.¹²⁷ Moreover, none of the Joint Utilities outline a significant forward sales strategy in testimony or during hearing. Nothing in the record suggests that they have a coherent strategy for selling resources on a long-term basis. Given these circumstances, and understanding that the Joint Utilities' actions put customers in the current strained position, it is unrealistic to expect that the Joint Utilities can suddenly produce a sales strategy that maximizes portfolio value. Thus, TURN's alternatives must be considered longer term solutions.

D. The Joint Utilities' Criticisms of CalCCA's Proposals Are Unfounded

The Joint Utilities reject CalCCA's proposals on many fronts, relying mainly on unsubstantiated claims, and ignoring obvious facts.

1. Reassessing RA Value

The Joint Utilities' urge rejection of CalCCA's proposal to use CPM and the long term capacity value in place of the current benchmark for capacity value. Although without legislative support for the proposition, the Joint Utilities assert that the long term values proposed have "no connection to actual market values," and erroneously introduce long-run capacity value into an RA benchmark "intended to capture short-run capacity value."¹²⁸ This assertion ignores the revenues the utilities could potentially obtain for capacity from Cost Allocation Mechanism (CAM), Reliability Must Run (RMR) contracts, the Capacity Procurement Mechanism (CPM), bilateral contracts, asset sales and other potential non-short term RA market sales.

¹²⁶ See generally 4 Tr. 805:5-809:7 (Joint Utilities/Cushnie, Lawlor).

¹²⁷ *Id.* 807:19-28.

¹²⁸ Joint Utilities Opening Brief at 19

As the Joint Utilities would admit, many of their resources are necessary for reliability and therefore could generate CAM, RMR, CPM or other revenues. Moreover, the record in this proceeding demonstrates that multiple CPM and RMR transactions were entered into for 2018.¹²⁹ On that basis and given that both generators and LSEs use the CMP price as a benchmark for their negotiation of RA prices in bilateral transactions, the short-term value of RA in 2018 clearly is more reasonably represented by the CPM price than by the reported value of a limited and stale set of transactions. If, as the Joint Utilities assert, value is equal to receipts, these receipts should be included in any calculation of RA “value.”

2. Continuation of 10-Year Limitation on Post 2002 UOG Recovery

The Joint Utilities assert that the presumption of a 10-year limit on PCIA recovery of post 2002 UOG was “arbitrary” and should be eliminated.¹³⁰ In fact, that limitation was heavily litigated and lobbied for. It was the result of a compromise by which the Commission provided some guaranteed cost recovery to the IOUs while the IOUs were attempting to invest in a hybrid, competitive market for new resources. If the Commission does consider lifting the 10-year limit, it may also want to consider whether IOU ROE on those resources should be eliminated, as well.

3. Proposed \$25/MWh GHG-Free Adder

The Joint Utilities also assert that the concept of a GHG-free adder “ignores the basic structure of GHG regulation in California and resulting CAISO market

¹²⁹ Exh. CalCCA-1 at 2B-8.

¹³⁰ *Id.* at 25.

operations.”¹³¹ Because GHG-emitting resources include their compliance costs in the bids they submit to the CAISO, the Joint Utilities argue, market prices realized through the CAISO already reflect the cost of GHG compliance.¹³² However, this argument completely fails to recognize that compliance cost is not the same as a GHG-free value. A resource mix that is all fossil (paying the appropriate compliance cost) is not the same as a GHG-free portfolio, either from a regulatory standpoint, a policy standpoint, a pollution standpoint, an advertising standpoint or a market price stand point.

Finally, to clarify a point the Joint Utilities raised, CalCCA in its testimony regarding the uneconomic cost of the legacy UOG states a 2018 value of PG&E’s hydro and nuclear of \$44.93/MWh.¹³³ The implied GHG adder would be the difference between PG&E’s \$85/MWh benchmark for GHG-free generation from the Diablo Canyon proceeding, and the 2018 PCIA MPB values for brown energy and RA. This figure is much higher than the PCIA benchmark, which CalCCA’s witness Mr. Kinoshian suggested at the time of the Diablo Canyon proceeding. It also suggests a GHG adder of \$40/MWh (\$85-\$44.93/MWh).

E. CLECA’s Observation Regarding the Existence of Three “Flavors” of Resource Adequacy While Correct Cannot Be Addressed.

CLECA recommends that the Commission “allow for differentiation of the types of RA for the capacity benchmark.”¹³⁴ The recommendation rests on Dr. Barkovich’s testimony that there are “three flavors of resource adequacy, which are system, local, and

¹³¹ *Id.* at 39.

¹³² *Id.*

¹³³ CalCCA-1 at 2B-21, table 2B-1.

¹³⁴ CLECA Opening Brief at 12.

flexible.”¹³⁵ CalCCA agrees with the underlying conclusion that there are functionally three different types of capacity required to support grid reliability and security. Making this observation, however, is not the same as offering a solution.

Increasingly, as exhibited in the 2016 RA Report, short-term prices for resource adequacy compliance products are differentiated by “flavor.” As CalCCA continues to emphasize, however, short-term RA is not the same product as long-term capacity, regardless of “flavor.” Moreover, even finding a “market price” for long-term local capacity may be challenging. As CalCCA witness Kinosian pointed out, using PG&E’s Humboldt plant as an example:

[T]here are no alternative facilities that could provide the needed generation at a lower price, and absent Commission regulation, PG&E could charge any price it wanted for Humboldt’s output.¹³⁶

In addition, the nature of local RA is changing, with SCE and PG&E increasingly relying on energy storage and a mix of distributed energy resources.¹³⁷ For these reasons, CalCCA proposed a single capacity value – neither system, local or flexible – that should adequately reflect the long-term value of resources underlying these short-term products.

F. CalCCA’s Corrected Methodology Is Moderate and Reasonable.

CalCCA’s near-term solution retains and corrects the Current Methodology. The heart of the corrections is: (1) reassessment of the value of capacity; (2) addition of a GHG-free energy value; and (3) limited modification of the Green Adder. The Joint Utilities¹³⁸ and TURN oppose these corrections.¹³⁹ CalCCA has responded to these

¹³⁵ 3 Tr. 526 (CLECA/Barkovich).

¹³⁶ Exh. CalCCA-1 at 2B-18:2-6.

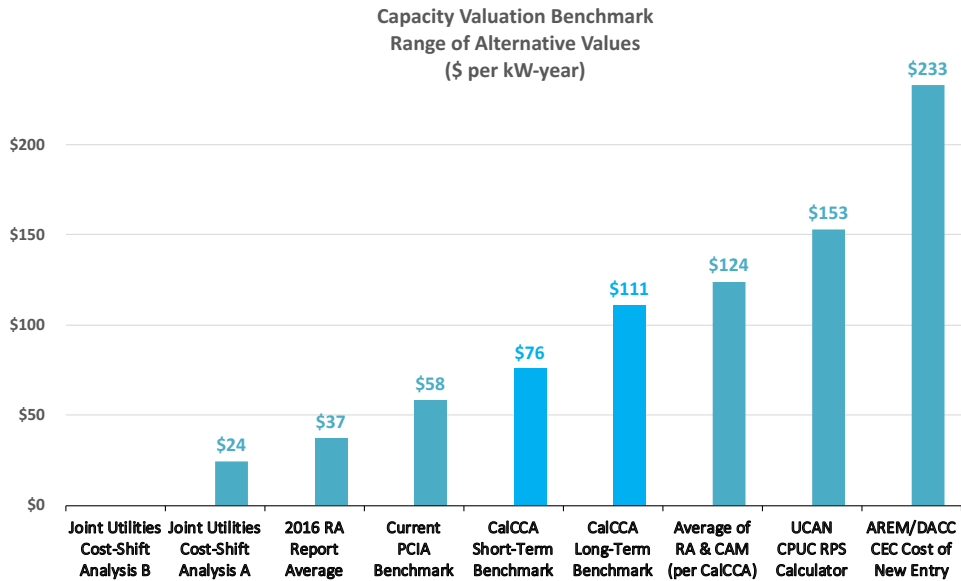
¹³⁷ *Id.* at 2B-7, n. 5.

¹³⁸ *See* Joint Utilities Opening Brief at 33-42 (opposing CalCCA proposals for correction to the capacity value, Green Adder and the addition of a GHG-free value).

criticisms above, but summarizes the range of alternative values advanced in the proceeding to provide context for the Commission’s decisionmaking.

CalCCA proposes to replace the Current Methodology’s short-term capacity value with a long-term capacity measure for capacity held in the portfolio, and a short-term value for surplus capacity.¹⁴⁰ Placing the proposal in the range of values put forward in this proceeding in Table 1 below shows that both the proposed short-term (\$76/kW-year) and long-term (\$111/kW-year) values are moderate and reasonable.

Table 1

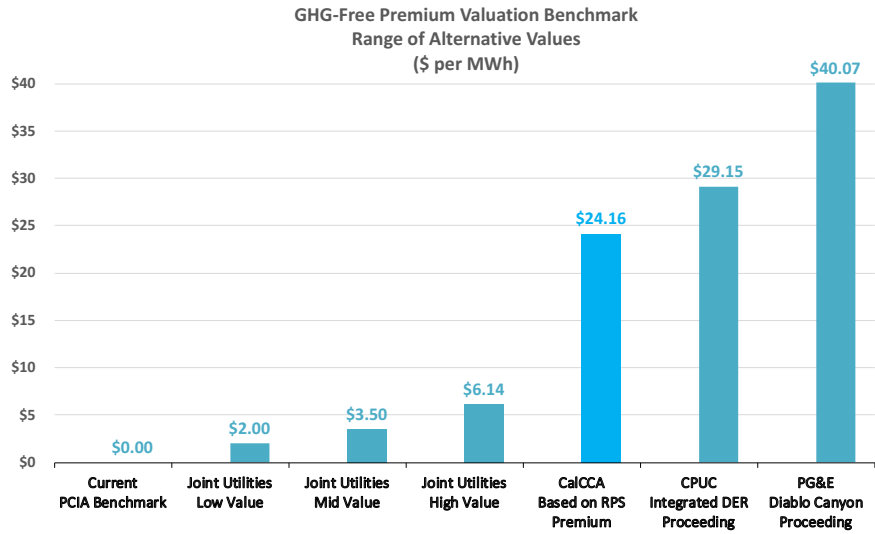


While CalCCA’s proposal is on the higher end of values discussed for GHG-free value, the array of values confirms that the value is not zero, as shown in Table 2. GHG-free energy is simply not equivalent in value to brown energy.

¹³⁹ See TURN Utilities Opening Brief at 8-12 (opposing corrections to capacity value and Green Adder corrections).

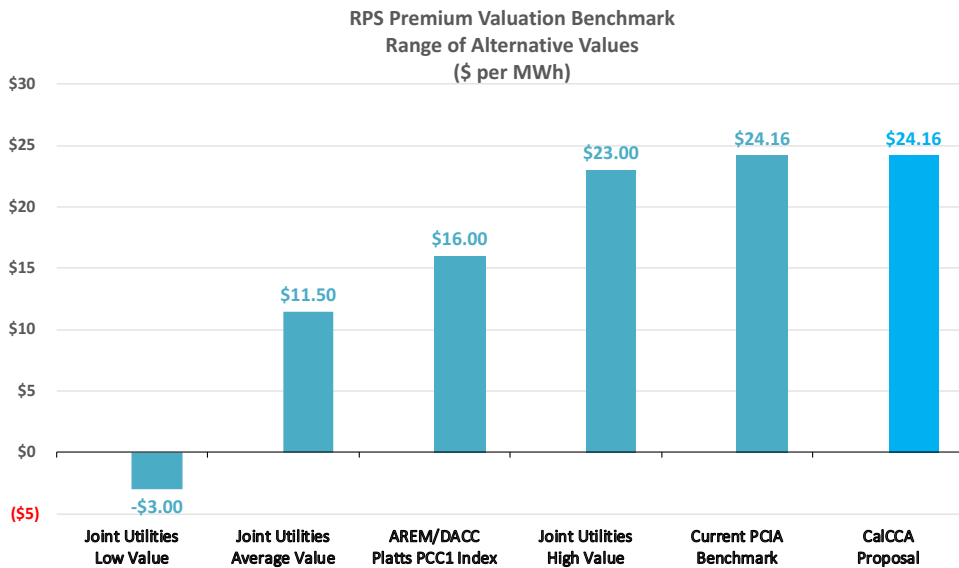
¹⁴⁰ CalCCA Opening Brief at 53.

Table 2



CalCCA’s proposed Green Adder, while producing a value at the high end of the range of discussed values as shown in Table 3, is based on a sound methodology and actual market price data for long-term transactions. The transactions involve resources that are actually part of the Joint Utilities’ portfolios and thus most reasonably represent the value of the resources in the portfolio.

Table 3



As discussed in Section IV, there are no precise, uncontestable values for most portfolio products and attributes. The Commission must, as it does regularly in other proceedings, exercise its best judgment in valuing the Joint Utilities' PCIA-eligible portfolios.

CalCCA submits that the values in its proposals are backed by a considered approach and analysis, and represent the most accurate and reasonable cost determination put forward by the parties.

VI. COST REDUCTION & PORTFOLIO OPTIMIZATION

A. The Commission Should Direct the Joint Utilities to Undertake All Reasonable Cost Reduction and Portfolio Optimization Measures.

Nearly all parties focused their case on slicing the PCIA pie, with little if any focus on the size of the pie. However, CalCCA, as a ratepayer advocate for its members' customers, identified two material opportunities for reducing the total PCIA cost: securitization of UOG assets and contract buydowns.¹⁴¹ Aside from the Joint Utilities, other active parties supported one or both measures. TURN supports the pursuit of both measures, although questioning the potential value of contract buydown transactions.¹⁴² CLECA lends support for securitization.¹⁴³ ORA proposes a working group on securitization.¹⁴⁴ CalCCA continues to stress that the Commission should direct the Joint Utilities to undertake all reasonable cost reduction measures.

The Joint Utilities acknowledge that securitization “may reduce portfolio costs, potentially benefitting both bundled service and departing load customers, and merits

¹⁴¹ *Id.* at 115-132.

¹⁴² TURN Opening Brief at 30-33.

¹⁴³ CLEAN Opening Brief at 26-27.

¹⁴⁴ ORA Opening Brief at 13-14.

further consideration.”¹⁴⁵ They attempt to defer the discussion, however, questioning whether CalCCA’s proposal is the “highest and best use” of funds from securitization and instead contemplate using those proceeds for additional infrastructure.¹⁴⁶

The Joint Utilities discourage the Commission from taking action in this proceeding, concluding that “such consideration must occur outside the instant proceeding.”¹⁴⁷ Their reticence to identify and advance cost reduction measures in this proceeding is striking. As noted in CalCCA’s opening brief, the Joint Utilities’ data forecast stranded costs of nearly **\$50 billion** through 2041.¹⁴⁸ The Commission and stakeholders should not take this forecast lightly and defer consideration of valuable measures to uninitiated proceedings. While the Joint Utilities may not be able to implement these options quickly, the Commission should direct active pursuit of these and all other cost-reducing measures that can reduce the total PCIA cost for all customers.

Portfolio optimizing could yield additional cost savings as well as to reduce the potential for “double procurement.” Scoping Memo issue 6 asks: “Should the Commission require and verify optimization of IOU portfolio management (e.g., contract extensions and contract renegotiation) in order to minimize above-market costs?” The Joint Utilities’ opening brief offers virtually no proposals¹⁴⁹ for portfolio optimization aside from the GAM/PMM, suggesting a complete lack of understanding of the problem they have fostered.

¹⁴⁵ Joint Utilities Opening Brief at 68.

¹⁴⁶ *Id.*

¹⁴⁷ *Id.* at 69.

¹⁴⁸ CalCCA Opening Brief at 1.

¹⁴⁹ Joint Utilities Opening Brief at 62-63.

It is difficult to see the conditions giving rise to this rulemaking as unforeseeable, unexpected or out of the Joint Utilities' control. As chronicled in CalCCA's opening brief,¹⁵⁰ current conditions are in large part a result of the Joint Utilities' conscious disregard of (not to mention opposition to) CCA formation and their failure to reduce their portfolios in the face of falling demand and generation costs over the past 16 years. Consider that when CDWR assumed responsibility for procuring long-term resources, it relied on a forecast with 3000 MW of departing load,¹⁵¹ which was not attached to any identified customers, yet the Joint Utilities refuse to forecast the possibility of CCA departing load in their long-term forecast unless and until they have a binding notice of intent in hand.¹⁵² The Joint Utilities further failed to take (and continue to take) any direct action in response to departing load.¹⁵³ They have also had very clear warnings over time regarding the need for careful portfolio management, including AB 1890's expectation that Legacy UOG would be water under the bridge by 2005,¹⁵⁴ and the Commission's repeated instruction that cost recovery from departing load for post-2002 UOG would be limited to 10 years.¹⁵⁵ The overall picture painted by this inaction calls into question whether the Joint Utilities' prudently managed their portfolios with due regard for all of the information available to them.

The failed portfolio management has had real consequences. For example, these practices saddled MCE customers with an allocated share of 1.7 GW of new generation capacity that was procured after PG&E had clear knowledge that MCE customers would

¹⁵⁰ See generally *id.* at 97-111.

¹⁵¹ See D.03-04-030 at 54.

¹⁵² CalCCA Opening Brief at 98.

¹⁵³ *Id.* at 104-106.

¹⁵⁴ D.95-12-063 at 58.

¹⁵⁵ See CalCCA Opening Brief at 37-38.

depart. Indeed, more than 600 MW, for which MCE customers have decades of financial responsibility, was procured *after* those customers departed.¹⁵⁶ Similarly, had the Joint Utilities acted on departing load as it occurred by actively managing their portfolios, customers who departed when prices were higher than they are today would be paying far less than they pay today for the PCIA. Finally, if the Joint Utilities had built flexibility into their procurement planning and decisions to recognize the growing departing load, as CalCCA proposes, they could have accommodated the departing load customers' choice to have the CCAs procure their future resource needs and obviated significant costs. These actions have damaged not only departing load, but all customers. The utilities have failed to adhere to the clear Commission requirement that they “dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs.”¹⁵⁷

The Commission should adopt the measures advanced in CalCCA's opening brief, requiring more active portfolio management and less conservative departing load forecasting.¹⁵⁸ In addition, the Commission should recognize the extent to which closer oversight is required. CalCCA witness Hoekstra proposed that, in evaluating any new resource commitment:

The Commission should make three explicit determinations: (1) the expected effect of the commitment on the PCIA rate for all vintages of departing load; (2) whether the utility's forecast of departing load was reasonable at the time the resource commitment was made; and (3) to which vintages of departing load the commitment is attributable.¹⁵⁹

¹⁵⁶ *Id.* at 99.

¹⁵⁷ CPUC AB 57, AB 380, and SB 1078 Procurement Policy Manual, IOU Standard of Conduct #4 at p. 5-11. Available online at:

<http://www.cpub.ca.gov/WorkArea/DownloadAsset.aspx?id=10906>

¹⁵⁸ CalCCA Opening Brief at 104-115.

¹⁵⁹ CalCCA-1 at 5-2:18-22.

Finally, the Commission should consider, in a separate phase of the proceeding, the need to modify vintaging where costs currently paid by departing load are not reasonably attributed to them and could have been avoided by the utility.

VII. OTHER ISSUES

A. The Joint Utilities' Proposal to Make Select Resources "Non-Vintaged" Is Unreasonable

The Joint Utilities propose to eliminate "vintaging" of resources that have been procured as a result of "Commission mandated procurement irrespective of whether the IOU needs the resources to serve its load."¹⁶⁰ The Joint Utilities call out the Renewable Market Adjusting Tarff (ReMAT), the Bioenergy Market Adjusting Tariff (BioMAT) and Renewable Auction Mechanism (RAM).¹⁶¹ CalCCA opposes this proposal.

CalCCA witnesses pointed out that these programs are not designed to be *incremental to RPS* requirements, but are mandated tools for the Joint Utilities to use to meet their compliance obligations.¹⁶² They further pointed out that "[w]hile costs may be higher, they are no different than procurement of an RPS resource under a different type of RPS solicitation."¹⁶³ The Commission, with respect to the Joint Utilities, and the Legislature have "authority to dictate how the utilities meet their RPS requirements, and they have exercised this authority in mandating procurement under RAM, ReMAT and BioMAT."¹⁶⁴ Local authorities are in the same position with respect to CCAs, and CCAs are undertaking similar programs *without* mandates. CCAs have begun to implement

¹⁶⁰ Joint Utilities Opening Brief at 88.

¹⁶¹ Joint Utilities Opening Brief at 88-89.

¹⁶² Exh. CalCCA at 7-1:13-16.

¹⁶³ *Id.* at 7-2:6-7.

¹⁶⁴ *Id.* at 7-2:11-13.

“targeted programs tailored to their communities’ needs to meet their RPS compliance obligations – programs whose costs are not spread to bundled customers.”¹⁶⁵

In addition, imposing costs for procurement entered into after a customer departs would fail to provide adequate notice of departing load obligations, counter to long-standing state policy. CalCCA’s witness explained that “departing load charges followed the practice of grandfathering customers that had departed prior to the notice of potential cost responsibility.”¹⁶⁶ He further explained “[t]o changes the rules in the middle of the game, imposing these costs without any notice of the obligations for these charges when a customer departs, would fail to provide reasonable notice.”¹⁶⁷

For all of these reasons, the Commission should reject the Joint Utilities proposal.

B. The Commission Should Accommodate Requests for Rate Caps on a Case-by-Case basis in the ERRA Forecast Proceedings.

AReM/DACC, TURN and others offer proposals to cap the PCIA rate on a year-to-year basis, while the Joint Utilities oppose any such caps. CalCCA agrees that circumstances could arise where a rate cap would be reasonable to protect customers. LSEs should thus have the right, on a case-by-case basis, to propose rate caps in the ERRA forecast proceedings. This approach is similar to rate capping in General Rate Cases, where the Commission decides on case-by-case basis whether a rate cap is needed to prevent rate shock.

¹⁶⁵ *Id.* at 7-4:7-9 (providing examples of Sonoma Clean Power and Marin Clean Energy programs aimed at small resource development).

¹⁶⁶ *Id.* at 7-3:5-7.

¹⁶⁷ *Id.* at 7-3:20-22.

The Joint Utilities¹⁶⁸ and TURN¹⁶⁹ assert that a rate cap violates the cost indifference. Yet, the Commission constantly shifts revenue requirements through balancing accounts and no party asserts a violation of cost indifference principles that exist across many programs and rates, not just the PCIA. And carrying this to the logical conclusion, even “forecast then true up” violates this "principle" since the costs would be out of balance during the year. The Commission should reject this specious, opportunistic argument.

C. CalCCA’s Forecasting Methodology is the Only Reasonable Approach to Enable LSEs to Forecast Their Customers’ Future Departing Load Obligations

CalCCA proposes to require the Joint Utilities to provide a “reasonable, transparent, and repeatable process for forecasting long-term PCIA rates...”¹⁷⁰ CalCCA proposes that, with the continued use of the Modified Nondisclosure Agreement, the Commission can build off of the data framework developed for this proceeding. The Joint Utilities would be required to update in each forecast ERRA proceeding a subset of the data contained in the “ALJ Data Matrix” framed by the Administrative Law Judge in this proceeding.

The Joint Utilities ignore CalCCA’s proposal by focusing on the nature of the forecast—REC and RA allocation—that would be required if the GAM/PMM is adopted.¹⁷¹ As CalCCA proposes, the Commission should rely on the framework developing in this rulemaking for ongoing PCIA rate forecasting to provide critically needed transparency and predictability for future PCIA obligations. CCAs need these

¹⁶⁸ Joint Utilities Opening Brief at 70.

¹⁶⁹ TURN Opening Brief at 33.

¹⁷⁰ See CalCCA Opening Brief at 142-43.

¹⁷¹ Joint Utilities Opening Brief at 83-84.

data to understand the nature and magnitude of their PCIA cost responsibility to effectively conduct planning, procurement and risk management.

D. The Joint Utilities’ Resistance to Including Uneconomic Costs as a Line Item on Bundled Customer Bills is Unjustified and Unsupportable

CalCCA proposes that the Joint Utilities present the PCIA rate or other uneconomic cost representation on bundled customer bills for greater rate and bill transparency. Requiring explicit identification of these costs would ensure that all customers, regardless of their supplier, have the same information about the nature of the utility’s uneconomic cost of service. The Joint Utilities oppose adoption of this measure at this time, justifying their position only by suggesting to “hold one or more workshops in 2019 to identify the impacts of this change on existing GRC Phase 2 settlements and the Joint Utilities’ tariff and billing systems.”¹⁷²

The Joint Utilities have provided little to no explanation or justification of their contention of a potential settlement violation or problem with billing systems. However, they have indicated that “more transparency is better.”¹⁷³ The issue was presented in CalCCA’s opening testimony, and the Joint Utilities’ failure to adequately address this issue should not prevent the Commission from adopting a simple, obvious change in bill presentation. The Commission should mandate the creation of a separate line item for the PCIA rate on all bills, for both bundled and departed customers.

¹⁷² Joint Utilities Opening Brief at 85-86.

¹⁷³ 3 Tr. 494:10-22 (Joint Utilities/Everett).

E. Prepayment Should Be Permitted Subject to Review.

CalCCA¹⁷⁴ and AReM/DACC,¹⁷⁵ proposed the development of a methodology that could be used by LSEs and their customers interested in prepaying their future departing load obligation. A prepayment option would allow departing load customers to gain certainty and predictability in their uneconomic cost obligation. The Joint Utilities oppose prepayment on grounds that it would create forecast-related market risk, volumetric risk, and regulatory risk.¹⁷⁶

This Commission has approved prepayment options in the past, and prepayment has been used in other states in similar circumstances.¹⁷⁷ Moreover, not just bundled customers would assume risk; as the Joint Utilities agreed, the transaction could fall to the benefit of either bundled or departing load customers.¹⁷⁸ Indeed, under some circumstances *not* doing a prepayment transaction when available could be imprudent from the standpoint of bundled customers. Managing the risk of forward obligations is something the Joint Utilities do each and every time they procure a resource and in making decisions regarding how to manage existing resources. A prepayment arrangement is no different.

CalCCA's SPA will also increase certainty in the prepayment process. CalCCA witness Marrinan explained: "[t]he Staggered Portfolio Auction could provide valuable information to determine the current market value; for the full host of attributes contained

¹⁷⁴ CalCCA Opening Brief at 133.

¹⁷⁵ AReM/DACC Opening Brief at 33.

¹⁷⁶ Joint Utilities Opening Brief at 87.

¹⁷⁷ Exh. CalCCA-1 at 7-3;7-7-4:14.

¹⁷⁸ 3 Tr. 455:5-456:25 (Joint Utilities/Everett). LSEs entering into the transaction would bear a significant risk, since they likely would have no recourse in the event of further load departures that leave them holding the prepayment bag.

in various categories of resources with varying terms.”¹⁷⁹ Effectively, a prepayment transaction price could be set based on reliable market values, in the same way other resources sales are transacted in the SPA.

There may be circumstances in which prepayment makes economic sense to the utility and the departing load. The Joint Utilities acknowledge that “it is possible to calculation a pre-payment option that results in symmetrical risk...”¹⁸⁰ Foreclosing the possibility of prepayment thus makes little sense. The Commission should, instead, permit prepayment on a case-by-case basis, subject to its review and approval.

VIII. MECHANICS/IMPLEMENTATION

CalCCA’s proposal presents the simplest near-term solution, retaining the Current Methodology but substituting alternative values to correct portfolio valuation. In the longer term, CalCCA’s proposal offers the most comprehensive and effective long-term solution, addressing the growing mismatch between the Joint Utilities’ supply portfolio and bundled demand.

CalCCA proposes to correct and add attributes in calculating the benchmarks under the Current Methodology, requiring no methodological changes. This approach can easily be implemented effective for 2019 and, along with AReM/DACC’s proposal, is the only approach that reasonably enables near-term implementation. The Corrected Methodology would serve as a bridge to CalCCA’s proposed SPA or a similar mechanism.

CalCCA’s proposed SPA, a two-year auction mechanism, will take longer to fully develop and implement. CalCCA has acknowledged that the SPA is a conceptual

¹⁷⁹ Exh. CalCCA-1 at 7-5: 9-11.

¹⁸⁰ Exh. IOU-3 at 7-16.

framework and will require further analysis and dialogue to be developed into a fully implementable solution that meets the Commission's needs and policy preferences. The issues could be addressed in a new phase of this proceeding. Shortly after the issuance of a final decision, the Commission would initiate a series of workshops to develop and structure the auction, culminating in a final proposal supported by the affected parties by the end of June 2019. An Administrative Law Judge, who would generally oversee the process, would then issue a proposed decision adopting the SPA by the end of August 2019. A final decision would be issued by early October, providing two to three months of preparation for the first auction. The first auction would occur in January 2020, with seven additional auctions quarterly until the last auction occurs in September 2021.¹⁸¹

Several issues must be addressed to facilitate the SPA. As an initial matter, the Commission must resolve the question of Provider of Last Resort to remove any uncertainty in resource procurement. In addition, the following issues must be explored and resolved:

Who will conduct the auction? A neutral third party is the best solution. The Joint Utilities, who will be purchasers in the auction, should not also be placed in the position of running the auction

What will the Joint Utilities' roles be in the auction from a credit perspective? To the extent possible, CalCCA would prefer full assignment of contracts; if the contract or counterparty prevents that result, the output would need to be transferred to third-party purchasers, preferably by a back-to-back transaction that mirrors the original contract between the utility and generator.

To what extent can supply be auctioned in whole contracts and, to the extent infeasible, how should the remaining portfolio products and attributes be packaged for sale? It may be infeasible to sell some of the larger contracts intact, requiring the development of products from those contracts that maximize value retention.

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What percentage of eligible supply should be sold in each auction? CalCCA has initially proposed an equal distribution across the eight auctions, although market conditions could suggest a different approach.

Should contracts and products be sold for their full term, or should the length of the term be shorter? To the extent possible, CalCCA supports a term that reflects the term of the underlying resource.

What outside expertise should the Commission retain to assist in structuring the commercial details of the auction? It would be optimal for the Commission to seek outside assistance with structuring the commercial aspects of the auction, including product offerings, timing and size of auctions, adjustments to product offerings based on initial auction result and other details.

Another important issue is the allocation of supply and costs from resources not included in the auction. CalCCA recommends that the resources remain physically with the Joint Utilities' bundled load, with their "above market" costs allocated to other LSEs. The benchmark used to inform the allocation would be calculated, to the extent possible, calculated using values produced in the auction.

Program development and auction timelines are attached as Exhibits A and B.

IX. CONCLUSION

For all of the foregoing reasons, CalCCA recommends adoption of the Corrected Methodology, the Staggered Portfolio Auction and the complementary cost reduction and portfolio optimization measures.

Respectfully submitted,



Evelyn Kahl
Counsel to the
California Community Choice Association

June 15, 2018

Exhibit A

Staggered Portfolio Auction Program Development

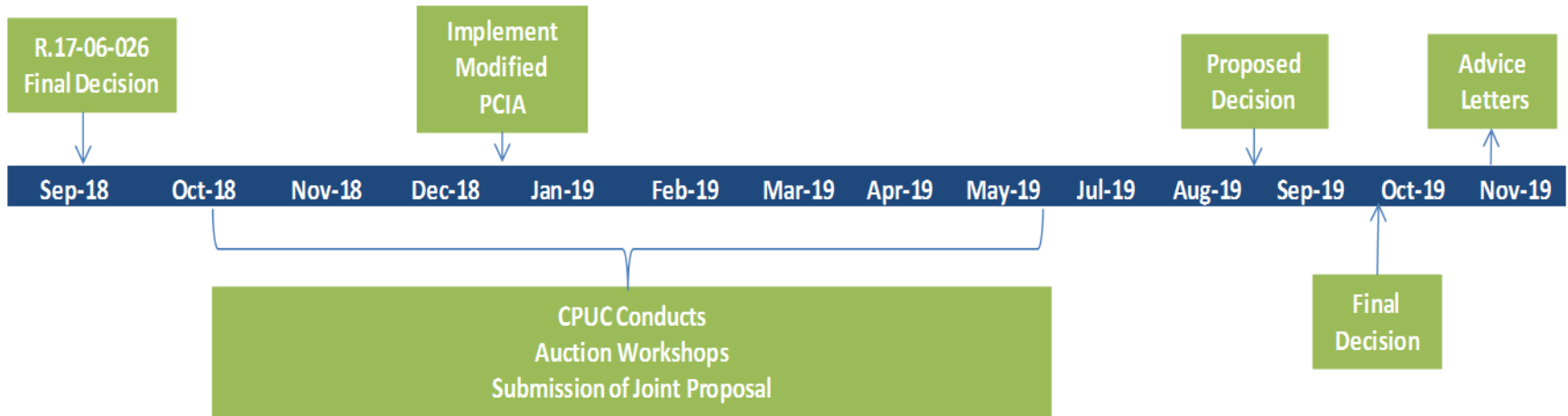
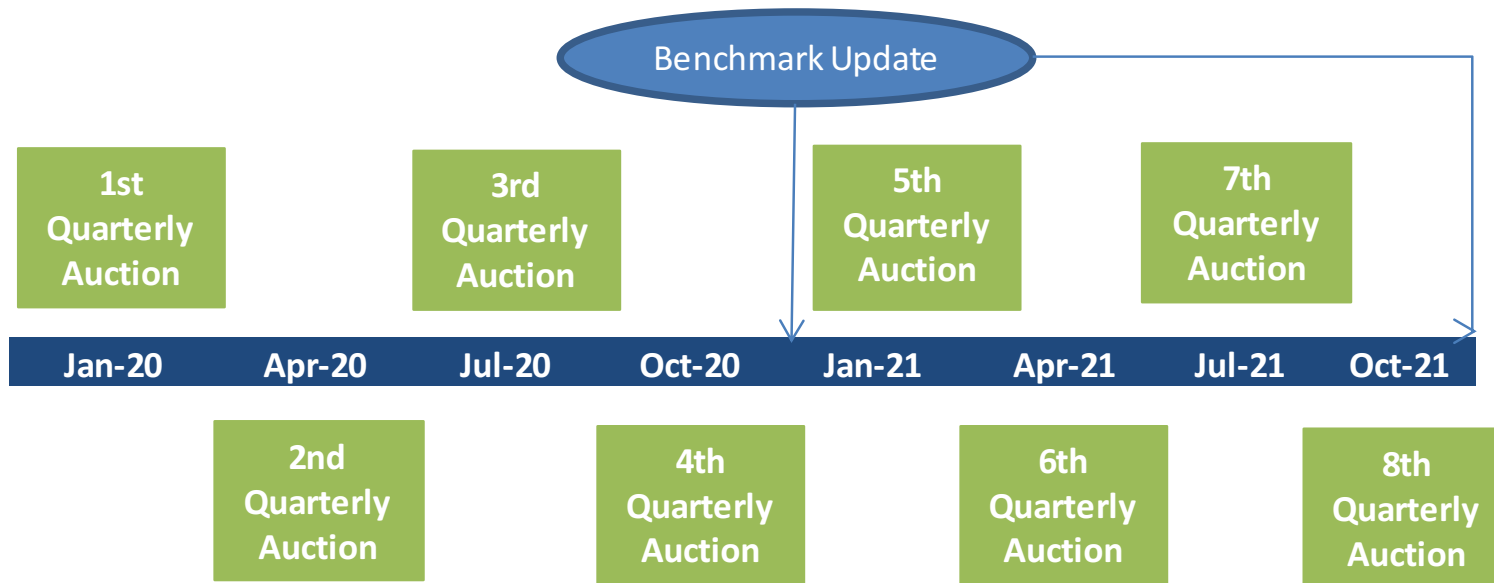


Exhibit B

Staggered Portfolio Auction Auction Timeline



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

Order Instituting Rulemaking to Develop a Successor)	
to Existing Net Energy Metering Tariffs Pursuant to)	
Public Utilities Code Section 2827.1, and to Address)	Rulemaking 14-07-002
Other Issues Related to Net Energy Metering.)	(Filed July 10, 2014)
)	

**REPLY COMMENTS OF THE CCA PARTIES
ON THE REVISED ALTERNATE PROPOSED DECISION**

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Dated: June 18, 2018

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

Order Instituting Rulemaking to Develop a Successor)	
to Existing Net Energy Metering Tariffs Pursuant to)	
Public Utilities Code Section 2827.1, and to Address)	Rulemaking 14-07-002
Other Issues Related to Net Energy Metering.)	(Filed July 10, 2014)
)	

**REPLY COMMENTS OF THE CCA PARTIES
ON THE REVISED ALTERNATE PROPOSED DECISION**

In accordance with Rule 14.3 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure, the City of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”), Peninsula Clean Energy Authority (“PCE”), and Sonoma Clean Power Authority (“SCP”) (collectively, “CCA Parties”) hereby submit these reply comments on the *Revised Alternate Proposed Decision of Commissioner Guzman-Aceves* (“Revised Alternate PD”) in the above-captioned proceeding.¹

In its opening comments on the Revised Alternate PD, Southern California Edison Company (“SCE”) recommends that “the Commission retain a Tier 3 advice letter process to implement the Revised APD DAC- and [Community Solar Green Tariff] programs.”² SCE notes that these programs present considerable complexities to resolve and details to implement, and recommends that these complexities and details be addressed through a Tier 3 advice letter implementation process.³

¹ Pursuant to Rule 1.8(d) of the Commission’s Rules of Practice and Procedure, MCE, PCE, and SCP have given counsel for the City of Lancaster permission to sign these comments on their behalf.

² SCE Opening Comments at 2.

³ *Id.*

The CCA Parties agree with SCE that the Commission should adopt a Tier 3 advice letter implementation process for both the Community Solar Green Tariff program and the Disadvantaged Communities – Green Tariff (“DAC-GT”) program. However, in order to ensure non-discrimination and competitive neutrality (as discussed in detail in the CCA Parties’ Opening Comments), both the Community Solar Green Tariff and DAC-GT programs and the the advice letter processes for implementing these programs should be open to Community Choice Aggregation (“CCA”) programs. In their implementation advice letters, CCA programs that elect to administer programs should be given the opportunity to describe their own *CCA-administered* programs, which, like the investor-owned utilities’ (“IOU”) programs, would qualify for funding from Commission-administered Greenhouse Gas (“GHG”) and Public Purpose Porgram (“PPP”) funds. For reasons discussed in the CCA Parties’ opening comments, CCA-administered programs should qualify for funding on equaly footing with the IOUs’ programs, and should be subject to comparable program requirements and Commission oversight in order to receive this funding.⁴

The CCA Parties agree with SCE that the Revised Alternate PD leaves a number of unresolved details regarding the implementation of the Community Solar Green Tariff and DAC-GT programs. This is especially true of the Revised Alternate PD’s lack of detail regarding CCA-administered programs. A lack of detail is understandable in many respects given the policy nature of the decision, and the process contemplated in the Revised Alternate PD for subsequent advice letter implementation. That said, the CCA Parties believe that it is important for the Commission to clearly articulate its interest in having CCA programs participate in

⁴ See CCA Parties Opening Comments at 4-6.

Community Solar Green Tariff and DAC-GT programs, and to accommodate those CCA programs that elect to administer such programs.

Recognizing that coordination and accommodation is necessary, the CCA Parties propose that, in addition to their individual Tier 3 implementation advice letters, the Commission may wish to require that CCA programs interested in forming and administering their own Community Solar Green Tariff and DAC-GT programs file a Tier 3 advice letter (either individually or jointly) proposing a process for Commission oversight of the use of GHG and PPP funds for CCA-administered programs. To allow for a sufficient amount of time for coordination and preparation, this advice letter should be required no earlier than 120 days of the adoption of the final decision.

The CCA Parties further note that in order to implement SCE’s proposed Tier 3 advice letter process in a manner that includes CCA-administered programs, additional modifications to the Revised Alternate PD and accommodations under the final decision will likely be required. For example, the Revised Alternate PD currently states that “At this time, the program administrator of the Community Solar Green Tariff program will be the utilities.”⁵ This statement should be revised to state “At this time, Community Solar Green Tariff program will be administered by the utilities and individual CCA programs that have elected to implement such programs pursuant to this decision.” Additional accommodations may be necessary, but presumably these accommodations can be defined and teased out as part of the implementation process.

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⁵ Revised Alternate PD at 80.

The CCA Parties thank the Commission for its consideration of the matters addressed in these reply comments. The CCA Parties are encouraged by the prospect of greater collaboration with the Commission on renewable energy programs for disadvantaged communities.

Dated: June 18, 2018

Respectfully submitted,

/s/ Scott Blaising

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And on behalf of the CCA Parties

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

Rulemaking 17-06-026
(Filed June 29, 2017)

**MARIN CLEAN ENERGY AND SONOMA CLEAN POWER
AUTHORITY NOTICE OF EX PARTE COMMUNICATION**

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June 20, 2018

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

Rulemaking 17-06-026
(Filed June 29, 2017)

**MARIN CLEAN ENERGY AND SONOMA CLEAN POWER
AUTHORITY NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rule 8.4 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure and Public Utilities Code (“Cal. P.U. Code”) Section 1701.1 and 1701.3(h)(2), Marin Clean Energy (“MCE”) and Sonoma Clean Power Authority (“SCPA”) hereby give notice of the following *ex parte* communication.

Neal Reardon, SCPA Director of Regulatory Affairs, initiated the communication on behalf of SCPA and MCE. The meeting was in-person and included oral and written communications. The meeting took place at the Commission’s offices in San Francisco on June 18, 2018 from approximately 1:30 p.m. to 2:00 p.m. The attendees included: John Reynolds, Advisor to Commissioner Peterman; Mitchell Shapson, Commission Staff Attorney, Nathaniel Malcolm, Policy Counsel for MCE; and Neal Reardon, Directory of Regulatory Affairs for SCPA. Due to the breadth of the topics discussed during this *ex parte* communication, this notice is being served on the service lists for the above-captioned proceeding and the Integrated Resource Planning (“IRP”) proceeding, Rulemaking (“R.”) 16-02-007.

MCE and SCPA voiced their position that the Joint Utilities’ Green Allocation Mechanism (“GAM”) violates statute by allocating products instead of costs to Community Choice Aggregators (“CCA”). The involuntary allocation of Renewable Energy Credits (“RECs”) via the

GAM would also severely interfere with a CCA's statutory authority to be solely responsible for procurement decisions on behalf of the local communities and customers it serves.

MCE and SCPA provided a graphical presentation of the GAM's projected effects on established CCAs with developed, long-term procurement plans. Specifically, MCE and SCPA illustrated that both CCAs are currently exceeding annual Renewable Portfolio Standard ("RPS") requirements and are projected to meet and exceed RPS requirements through 2030 without GAM allocations. Superimposing forecasted GAM allocations on MCE's current long-term portfolio would put MCE's portfolio above 90% RPS in 2019 and over 100% RPS in 2024; superimposing GAM allocations on SCPA's portfolio would put its portfolio at 73% RPS in 2019 and nearly 70% RPS in 2024. MCE and SCPA expect this trend to continue through 2030 if the GAM were approved.

MCE and SCPA emphasized they are already positioned to meet their respective long-term RPS contracting requirements under Senate Bill 350 (Cal. P.U. Code Section 399.13(b)) starting in 2020 and continuing through 2030 without GAM allocations. Moreover, MCE and SCPA forecast that GAM allocations will come at a cost of approximately \$169 million for MCE in 2019 and approximately \$79 million for SCPA in 2019.

MCE and SCPA also indicated that forcing MCE and SCPA to be excessively long on RPS would potentially bring Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") well under RPS compliance. In this context, MCE and SCPA addressed the California Community Choice Association's ("CalCCA") voluntary Staggered Portfolio Auction ("SPA") as a way for all Load Serving Entities ("LSE") to acquire the RPS resources needed to serve their forecasted loads and meet, or voluntarily exceed, RPS requirements. The SPA could accomplish this result without forcing particular LSEs to be involuntarily long on RPS;

procurement decisions would be voluntary and based on an individual LSE's needs and procurement strategies.

Finally, MCE and SCPA also voiced concerns that the GAM, unlike the SPA, would not provide CCAs the underlying energy associated with the allocated GAM RECs. The uncertain timing and volumes of GAM allocations would force CCAs to rely heavily on spot market purchases to meet their daily and hourly loads, despite their long-term procurement activities. Moreover, MCE and SCPA questioned the legality of the Joint Utilities' proposal to treat GAM allocated RECs as Portfolio Content Category 1 RECs. MCE and SCPA also broached concerns that the GAM is not compatible with the Clean Net Short methodology adopted recently in the IRP proceeding, R.16-02-007.

During the communication, written materials were provided to Mr. Reynolds and Mr. Shapson by Mr. Malcolm of MCE and Mr. Reardon of SCPA. These materials are attached to this notice as Attachment A.

Respectfully submitted,

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June 20, 2018

ATTACHMENT A
WRITTEN COMMUNICATIONS

MCE Notice of Ex Parte Communication



Local. Renewable. Ours.



Meeting with Commissioner Peterman's Office Power Charge Indifference Adjustment (R.17-06-026)

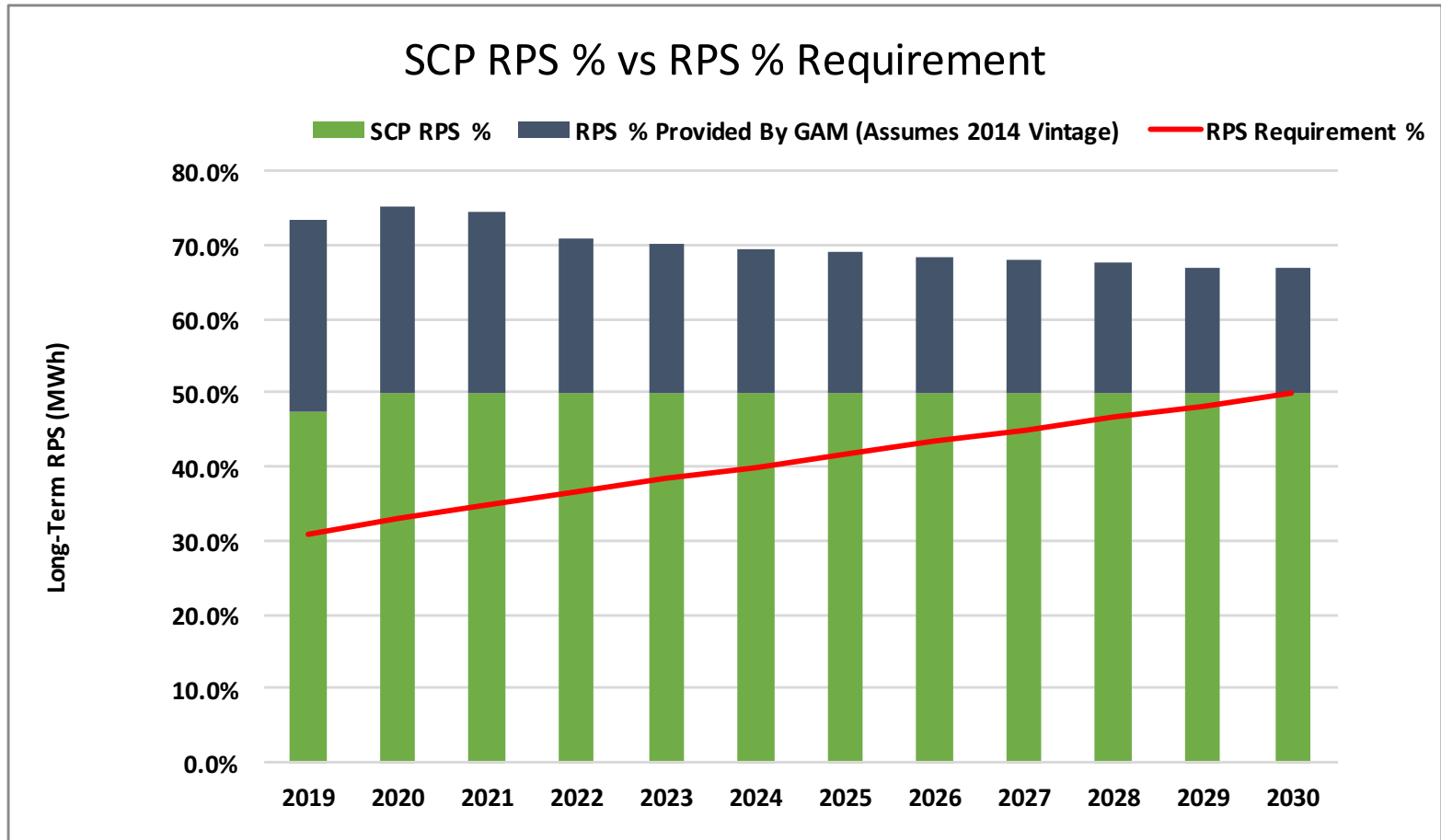
Neal Reardon, Sonoma Clean Power
Nathaniel Malcolm, MCE Clean Energy
June 18, 2018

GAM is not legal, efficient, equitable, practical, or cost-effective

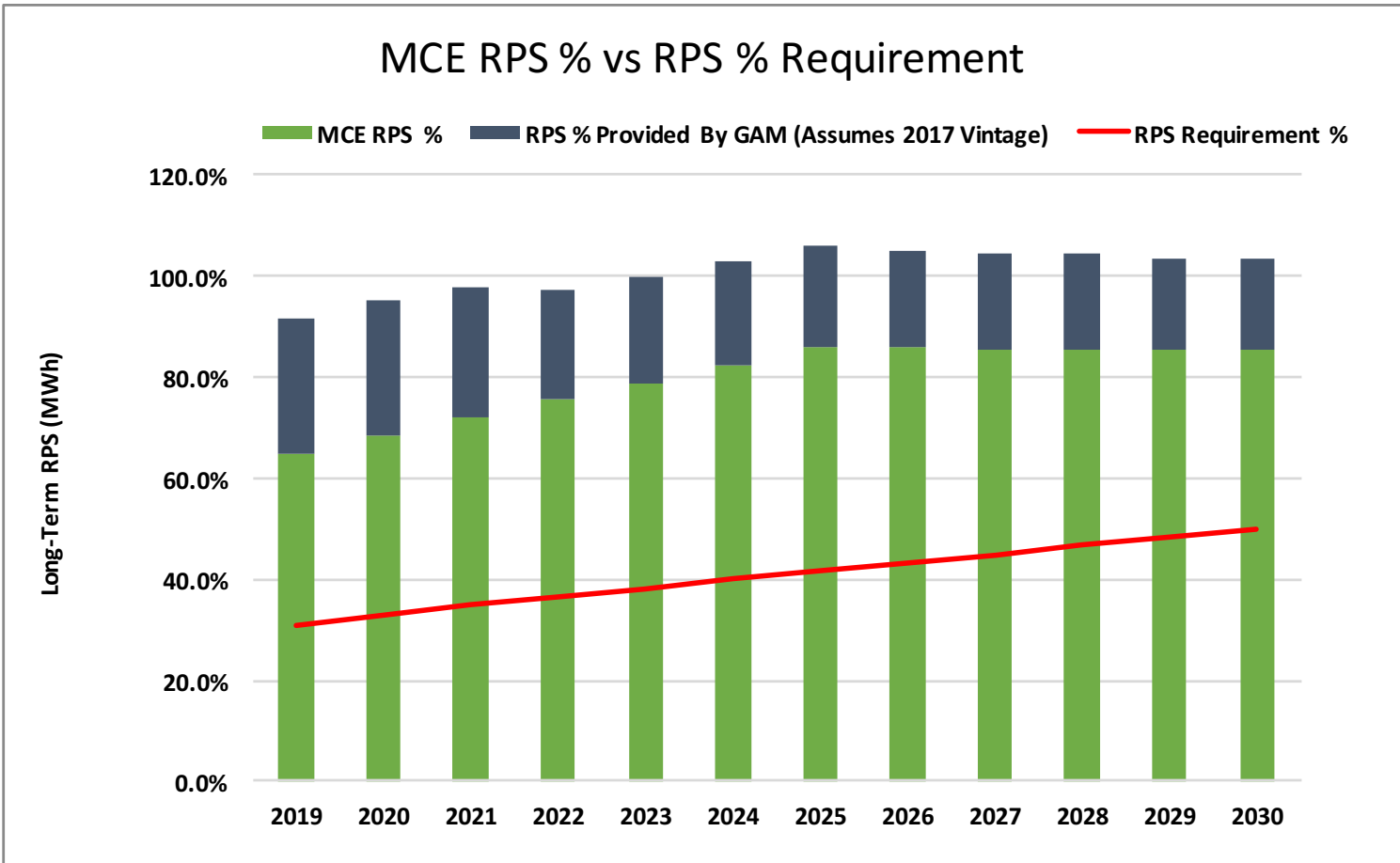
- Illegal: PU Code provides for allocation of net unavoidable costs, not *products*
- Inefficient: Dumps RECs after-the-fact, leaving CCAs unable to plan or hedge, would eliminate RPS procurement by CCAs and increase GHGs
- Inequitable: IOUs would control majority of assets while serving only 15% of load, creating anti-competitive scenario and continued litigation
- Impractical: Existing CCAs have made long-term plans and procured accordingly, consistent with statute
 - GAM would cause most harm to mature CCAs with long-term contracts
- Expensive: 2019 GAM Allocations would represent
 - \$79M for SCP and \$169M for MCE
 - \$30.72/MWh; ~50% increase over retail generation rates

Impact of GAM on Existing CCA: SCP

>75% RPS in 2020 vs. 33% Requirement

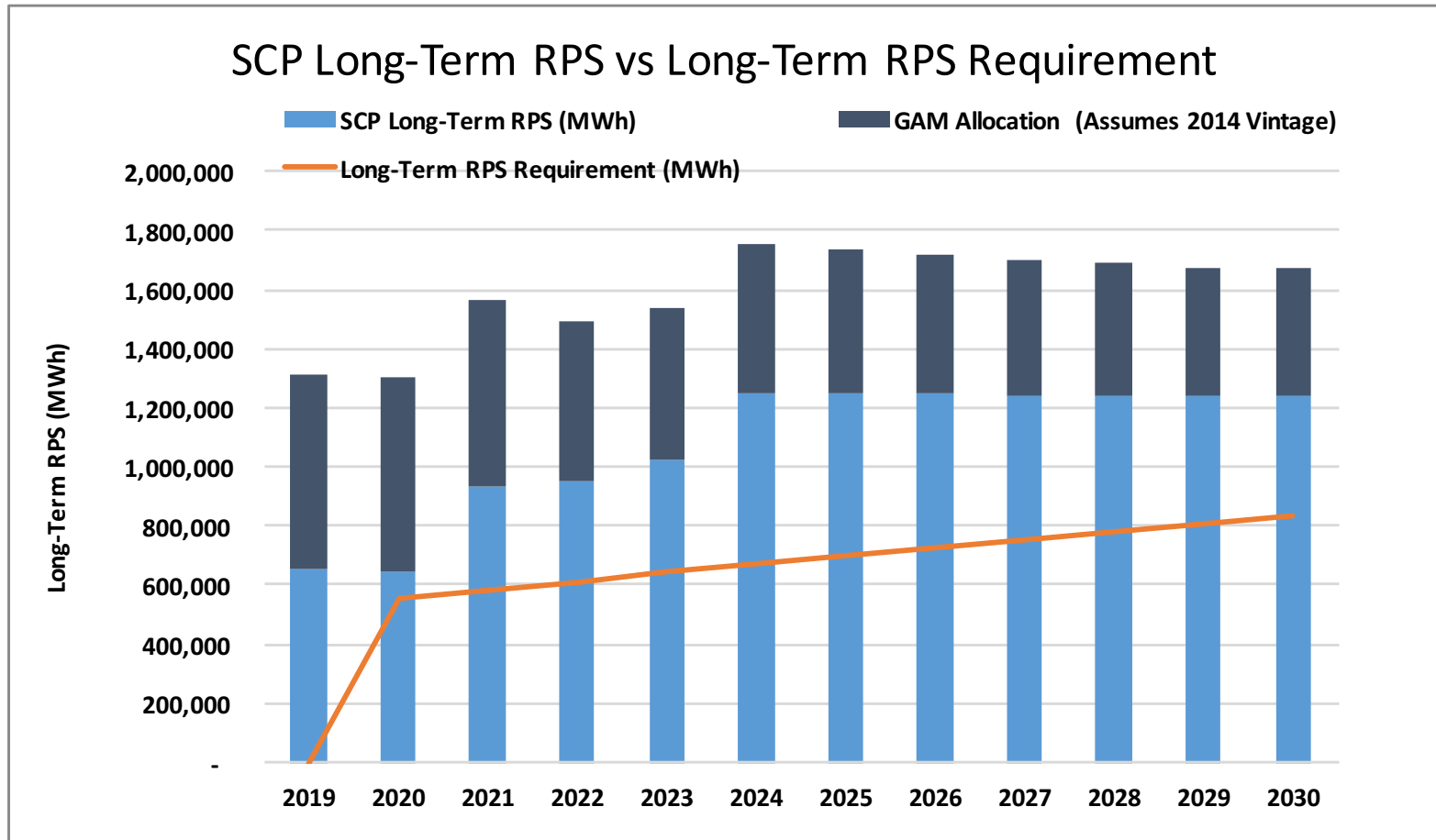


Impact of GAM on Existing CCA: MCE >100% RPS in 2023 and onwards



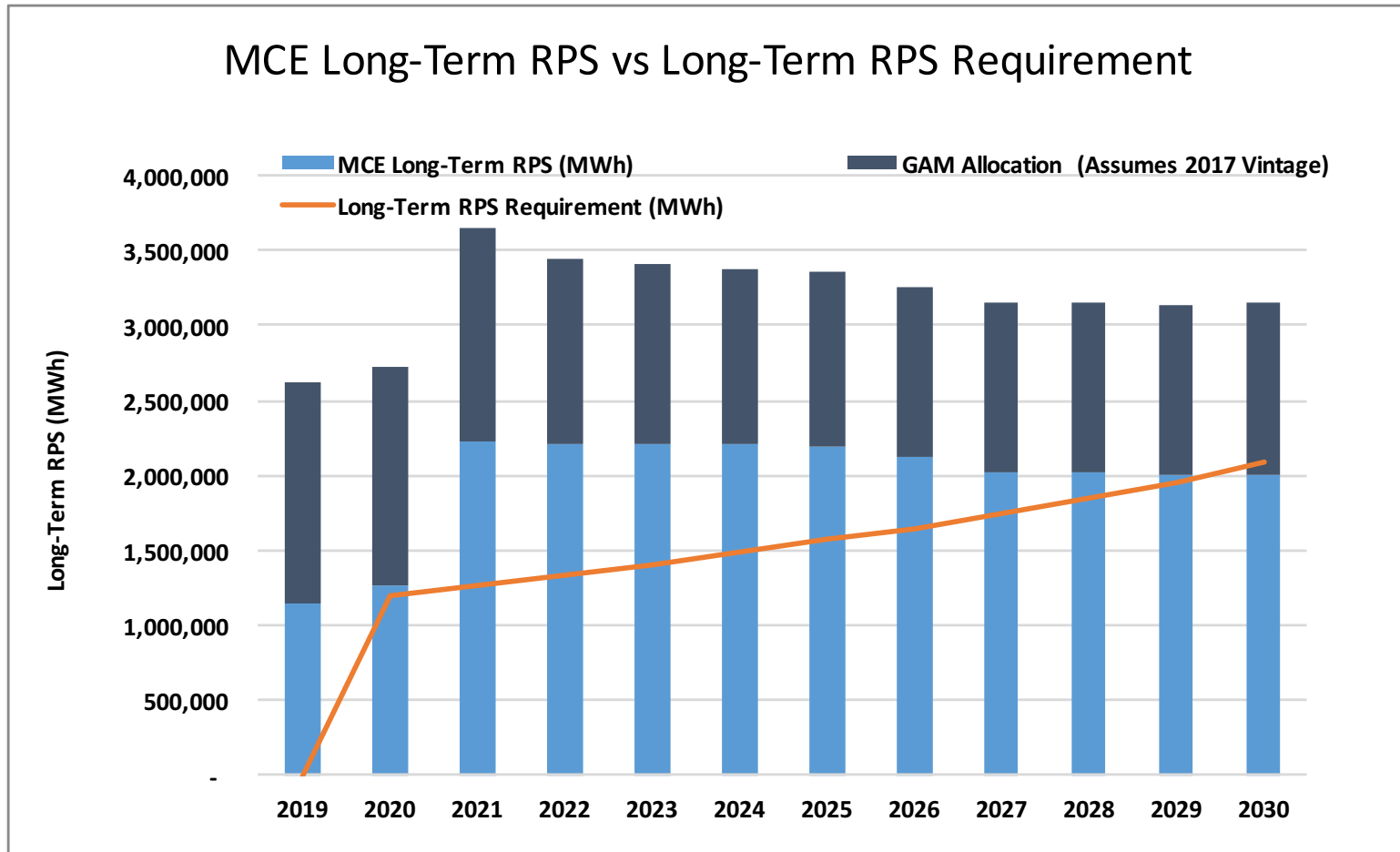
Impact of GAM on Existing CCA: SCP

>930 GWH Long-term RPS in 2021 vs. 584 Requirement



Impact of GAM on Existing CCA: MCE

>2,222 GWH Long-term RPS in 2021 vs. 1,261 Requirement



By Comparison: Impact of GAM on IOU Portfolios 2025 Sample year

RPS-Eligible Energy (GWh)
Supply/Demand Illustration

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	12-Yr Total
IOU RPS % (Pre-GAM Allocation) (NOTE: REFLECTS CURRENT-YEAR PROCUREMENT ONLY SO IGNORES BANK IMPACTS)													
PG&E	44%	43%	42%	36%	35%	34%	33%	32%	31%	31%	29%	29%	35%
SCE	49%	53%	55%	54%	53%	52%	51%	50%	46%	43%	43%	42%	49%
Subtotal	47%	48%	48%	45%	44%	43%	42%	41%	39%	37%	36%	35%	42%

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	12-Yr Total
IOU RPS % (Post-GAM Allocation) (NOTE: REFLECTS CURRENT-YEAR PROCUREMENT ONLY SO IGNORES BANK IMPACTS)													
PG&E	27%	26%	25%	22%	21%	20%	20%	19%	19%	18%	18%	17%	21%
SCE	30%	32%	33%	32%	32%	31%	31%	30%	28%	26%	26%	25%	29%
Subtotal	28%	29%	29%	27%	26%	26%	25%	25%	23%	22%	22%	21%	25%

Load Serving Entity	2025 RPS (%)	2025 Requirement (%)
PG&E	20	42
SCE	31	42
Sonoma Clean Power	69	42
MCE Clean Energy	106 %	42

Note: Assumes 40% load departures, does not include confidential banking data

Appendix A: GAM SCP Figures

Appendix: GAM Impact on Sonoma Clean Power												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast load MWh	2,557,467	2,580,792	2,583,373	2,578,206	2,573,050	2,570,477	2,567,906	2,565,338	2,562,773	2,560,210	2,557,650	2,555,092
RPS Requirement %	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%
RPS requirement MWh	792,815	851,661	899,014	941,045	985,478	1,028,191	1,070,817	1,110,792	1,153,248	1,195,618	1,235,345	1,277,546
Long term RPS requirement %	0	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Long-Term RPS Requirement (MWh)	-	553,580	584,359	611,679	640,561	668,324	696,031	722,014	749,611	777,152	802,974	830,405
SCP RPS %	47.6%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
SCP RPS % with GAM	73.5%	75.4%	74.5%	70.9%	70.0%	69.5%	69.2%	68.3%	67.9%	67.7%	67.0%	66.8%
RPS % Provided By GAM (Assumes 2014 Vintage)	25.9%	25.4%	24.5%	20.9%	20.0%	19.5%	19.2%	18.3%	17.9%	17.7%	17.0%	16.8%
GAM Allocation (Assumes 2014 Vintage)	661,963	654,456	634,147	538,815	514,647	500,361	491,824	469,557	457,710	452,833	433,934	430,032
SCP RPS procured MWh	1,216,573	1,191,365	800,805	799,815	798,838	799,056	796,883	795,917	356,946	355,988	355,033	354,080
SCP RPS under negotiation/planned MWh			287,008	313,037	382,027	451,018	450,068	449,122	448,181	447,245	446,314	445,387
SCP existing contract re-up MWh									438,000	438,000	438,000	439,200
SCP short term RPS true up MWh		99,031	203,874	176,251	105,660	35,165	37,003	37,630	38,259	38,872	39,478	38,879
SCP Total RPS MWh	1,216,573	1,290,396	1,291,686	1,289,103	1,286,525	1,285,238	1,283,953	1,282,669	1,281,387	1,280,105	1,278,825	1,277,546
SCP Total RPS MWh with GAM	1,878,536	1,944,852	1,925,834	1,827,918	1,801,172	1,785,600	1,775,777	1,752,226	1,739,096	1,732,939	1,712,759	1,707,578
SCP Long-Term RPS % with GAM	165.6%	152.6%	174.0%	158.8%	156.0%	170.2%	162.4%	154.4%	147.5%	141.7%	135.5%	130.6%
GAM Allocation (Assumes 2014 Vintage)	661,963	654,456	634,147	538,815	514,647	500,361	491,824	469,557	457,710	452,833	433,934	430,032
SCP long term RPS procured MWh	650,891	645,321	643,125	642,135	641,158	799,056	796,883	795,917	356,946	355,988	355,033	354,080
SCP long term RPS under negotiation/planned MWh			287,008	313,037	382,027	451,018	450,068	449,122	448,181	447,245	446,314	445,387
SCP existing contract re-up MWh									438,000	438,000	438,000	439,200
SCP Long-term RPS (MWh)	650,891	645,321	930,133	955,172	1,023,185	1,250,074	1,246,951	1,245,039	1,243,127	1,241,233	1,239,347	1,238,667
SCP Long-Term RPS MWh with GAM	1,312,854	1,299,777	1,564,280	1,493,987	1,537,832	1,750,435	1,738,775	1,714,596	1,700,837	1,694,067	1,673,281	1,668,699

Appendix B: GAM MCE Figures

Appendix: GAM Impact on MCE Clean Energy												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast Load MWh	5,512,252	5,544,283	5,579,058	5,618,200	5,664,714	5,718,596	5,781,807	5,857,733	5,950,241	6,072,436	6,222,491	6,408,290
RPS Requirement %	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%
RPS Requirement MWh	1,708,798	1,829,613	1,941,512	2,050,643	2,169,586	2,287,439	2,411,014	2,536,398	2,677,609	2,835,827	3,005,463	3,204,145
Long Term RPS Requirement %	0	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Long-Term RPS Requirement (MWh)	-	1,189,249	1,261,983	1,332,918	1,410,231	1,486,835	1,567,159	1,648,659	1,740,446	1,843,288	1,953,551	2,082,694
MCE RPS %	65.1%	68.7%	72.1%	75.5%	78.9%	82.3%	85.7%	85.7%	85.7%	85.7%	85.7%	85.6%
MCE RPS % with GAM	91.9%	95.0%	97.8%	97.5%	100.0%	102.8%	105.9%	105.0%	104.6%	104.4%	103.6%	103.4%
RPS % Provided By GAM (Assumes 2017 Vintage)	26.8%	26.3%	25.7%	22.0%	21.1%	20.5%	20.2%	19.3%	18.9%	18.7%	18.0%	17.8%
GAM Allocation (Assumes 2017 Vintage)	1,476,113	1,459,800	1,432,010	1,235,976	1,194,093	1,174,074	1,168,009	1,132,890	1,123,177	1,135,313	1,118,077	1,141,808
MCE RPS Procured MWh	2,014,473	1,824,289	2,251,755	2,245,225	2,239,705	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE RPS under Negotiation/Planned MWh	1,573,319	1,983,940	1,770,780	1,996,979	2,230,333	2,501,718	2,756,384	2,903,068	3,075,975	3,185,048	3,318,739	3,481,734
MCE Existing Contract Re-Up MWh												
MCE Short Term RPS True-Up MWh												
MCE Total RPS MWh	3,587,792	3,808,229	4,022,535	4,242,204	4,470,038	4,706,813	4,954,972	5,020,358	5,098,805	5,202,425	5,329,672	5,487,230
MCE Total RPS MWh with GAM	5,063,905	5,268,029	5,454,544	5,478,181	5,664,131	5,880,887	6,122,982	6,153,248	6,221,982	6,337,738	6,447,749	6,629,038
MCE Long-Term RPS % with GAM	153.7%	149.2%	188.2%	168.3%	156.9%	147.7%	139.6%	128.1%	117.5%	111.2%	104.1%	98.2%
GAM Allocation (Assumes 2017 Vintage)	1,476,113	1,459,800	1,432,010	1,235,976	1,194,093	1,174,074	1,168,009	1,132,890	1,123,177	1,135,313	1,118,077	1,141,808
MCE Long Term RPS Procured MWh	1,150,373	1,270,189	2,222,655	2,216,125	2,210,605	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE Long Term RPS under Negotiation/Planned MWh												
MCE Existing Contract Re-Up MWh												
MCE Long-Term RPS (MWh)	1,150,373	1,270,189	2,222,655	2,216,125	2,210,605	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE Long-Term RPS MWh with GAM	2,626,486	2,729,989	3,654,665	3,452,102	3,404,697	3,379,169	3,366,597	3,250,180	3,146,007	3,152,690	3,129,010	3,147,304

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

**ADDITIONAL BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**



June 25, 2018

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Counsel to the
California Community Choice Association

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
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R.17-06-026
(Filed June 29, 2017)

**ADDITIONAL BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

Pursuant to Rule 13.11 of the California Public Utilities Commission’s Rules of Practice and Procedure, the Amended Scoping Memo and Ruling of Assigned Commissioner issued March 2, 2018 in R.17-06-026, and Administrative Law Judge Roscow’s email directive of June 6, the California Community Choice Association (CalCCA) submits this additional brief.

I. JOINT UTILITIES’ POSITION THAT GAM/PMM IS COMPLETELY AND IMMEDIATELY IMPLEMENTABLE IS BASELESS.

The Joint Utilities have argued that GAM/PMM is the only proposal that is “immediately implementable.”¹ They also state that GAM/PMM is “completely implementable”, and would use the existing ERRA and other existing Commission ratemaking frameworks to “seamlessly transition from the existing PCIA to GAM/PMM on January 1, 2019.”² GAM/PMM, they argue, is fully scalable to all levels of departing load, and is, they claim, also fully scalable if and when load returns to the IOUs’ bundled service.³

¹ Joint Utilities Reply Brief at 8.

² *Id.* at 42.

³ *Id.*

CalCCA agrees with AReM/DACC, who state these claims are “nonsense.”⁴ CalCCA has described at length the numerous flaws in the GAM/PMM proposal and gaps that would have to be filled before this proposal could be implemented and function as the Joint Utilities claim. Not only is the GAM/PMM not able to be implemented in the near-term, it also is not viable even if the early implementation issues are addressed. The GAM/PMM is a fundamentally flawed methodology that is severely disruptive to the energy market, CCA procurement decisions and planning, and not workable as proposed.

First, changes would be required to the Power Content Label rules to ensure the proper accounting for resources subject to GAM/PMM.⁵ These issues are not within the scope of this Commission’s jurisdiction, but instead lie within the Energy Commission’s discretion.⁶ As TURN has correctly observed, the CEC’s Power Source Disclosure Program “is not currently configured to address the possible complications resulting from this approach” thus presenting “another wrinkle.”⁷ The Joint Utilities have still not explained how the GAM allocation would be treated under this program or what process would be required to effectuate the program.

In addition, also as TURN points out, in order to preserve allocated RECs’ compliance value under Section 399.13(b) under GAM/PMM, the Commission would have to ignore the “unbundling” of those RECs from the underlying resource. The Commission would also, presumably magically, have to deem the allocated unbundled RECs to be RECs of the *recipient LSE*.⁸ Assuming this were possible, even the Joint

⁴ AReM/DACC Reply Brief at 9.

⁵ Exh. IOU-1 at 4-45.

⁶ 2 Tr. 302:17-21.

⁷ TURN Opening Brief at 23.

⁸ Cal. Pub. Util. Code §399.13(b); *see* TURN Opening Brief at 20-21.

Utilities acknowledge that the allocated RECs would not retain the long-term, bundled characteristics if the recipient LSE traded them in the market⁹—an attribute required under state law to comply with the RPS.

This is particularly damaging and problematic to older CCAs that have procured long-term to comply with state policy goals and Commission rules. Such CCAs have already procured to meet their long-term RPS contracting requirements. GAM would thus force “devalued” RECs on these CCAs while charging CCAs and their customers the price of a fully bundled REC, thus raising significant concerns of cost-shifting to CCA customers. This inequity cannot be rectified in the short-term and represents a fundamental flaw in the Joint Utilities proposal and implementation claims.

Not least of all, the Joint Utilities’ proposal for REC allocations raises concerns about consistency with law under Pub. Util. Code Section 399.16(b). As such, the GAM proposal likely will require legislative action. This further deconstructs the Joint Utilities’ claims of simple and immediate implementation.

There are other barriers to “complete and immediate” implementation. For example, the GAM/PMM proposal does not clearly address the legal and regulatory basis for allocating banked RECs from the utility portfolios to other LSEs’ portfolios. Multiple recalculations of GAM RA amounts, as proposed, would also hardly ease the planning process for meeting RA requirements, and would effectively preclude responsible hedging by CCAs.¹⁰ The complex rules for replacement and substitution of RA resources that is proposed would pose a significant administrative burden to the Commission, as well as to IOUs and other stakeholders. Even the Joint Utilities acknowledge that a

⁹ 2 Tr. 367: 3-10. (Cushnie/Joint Utilities).

¹⁰ Exh. IOU-1 at 4-25:19 to 4-26:22.

stakeholder process will be required, prior to implementing GAM/PMM, to determine how to avoid stranding import RA.¹¹

Finally, the PMM auction would itself require the resolution of many issues before it could be implemented, including the utilities' potential placement on both sides of certain transactions. The possibility that the PMM auctions could be subject to gaming would also require serious consideration and, possibly, the adoption of preventive protocols.

As AReM/DACC has pointed out, although the Joint Utilities argue that their proposal can be implemented immediately, they go on to say that the implementation will involve the following steps:

- management of their respective generation portfolios through a *multitude of regulatory and commercial actions;*"
- the execution of "*sales transactions involving different types of energy products;*" and
- the conduct of "multi-year forward sales of RA capacity" that would occur twice a year.¹²

CalCCA echoes AReM's comment that "[i]f this is "simple" and can be done "immediately," it would be interesting to see what the Joint Utilities believe to be complex.¹³

Completely ignored by the Joint Utilities is the inability of the LSEs to modify the contents of existing and planned resources in their portfolios that could become excess under the construct. The Joint Utilities have failed to make any meaningful provisions for the management of these resources in a way that allows the LSEs to plan for the needs

¹¹ *Id.* at 4-49:23-33.

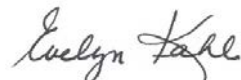
¹² AReM/DACC Reply Brief at 11, quoting Joint Utilities Opening Brief at 63.

¹³ AReM/DACC Reply Brief at 11.

of their customers efficiently and cost effectively, and to effectively mitigate their portfolio risk. No provisions are made for short-term or real-time resource availability or scheduling information for allocated resources that would be needed for the LSEs to balance and hedge their short-term positions. No provisions are made to allow the LSEs to depend on these resources past the current year for meeting the 65 percent long-term requirement for RECs under state law. No apparent consideration was given to what would be required by the LSEs to modify their risk policies and/or procurement to accommodate the resources or settlements that would be allocated to the LSEs. No calculation of the financial consequences to LSE customers has been presented by the Joint Utilities. The Joint Utilities' haphazard allocation proposal risks severely prejudicing CCAs through changes that would shift significant costs and force dramatic modifications to existing and planned portfolios to accommodate GAM allocations. CalCCA reiterates that the shifting of risk to unbundled customers as proposed in GAM/PMM would effectuate a cost shift that is not allowed by law.

The GAM/PMM proposal would require significant action by the Commission and the legislature, as well as by all stakeholders, and would result in unquantified cost and risk to departing load customers. Statements to the contrary are incorrect and misleading.

Respectfully submitted,



Evelyn Kahl
Counsel to the
California Community Choice Association

June 25, 2018

Application: 16-11-005

Exhibit: CalCCA-01

Date: June 28, 2018

Witness: Hilary Staver

**PREPARED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION**



Joint Application to Establish Non-Bypassable Charge)
 (“NBC”) for Above-Market Costs Associated with) Application No. 16-11-005
 Tree Mortality Power Purchase Agreements (“Tree) (Filed November 14, 2016)
 Mortality”) in Compliance with Senate Bill 859 and)
 Resolution E-4805.)
)

1 **PREPARED TESTIMONY OF**

2 **THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

3 **I. INTRODUCTION**

4 In accordance with the *Scoping Memo and Ruling of Assigned Commissioner*, dated May
5 30, 2018 (“Scoping Memo”), the California Community Choice Association (“CalCCA”)
6 submits the following prepared testimony. In an email ruling, dated June 18, 2018 (“Procedural
7 Ruling”), assigned Administrative Law Judge Patrick Doherty granted an extension of time to
8 and including June 28, 2018 to serve testimony.

9 This proceeding has been established “to establish a non-bypassable charge [(“NBC”)]
10 for above-market costs associated with tree mortality power purchase agreements [(“Tree
11 Mortality NBC”)] in compliance with Senate Bill [(“SB”)] 859 (Committee on Budget and Fiscal
12 Review, 2016) and Commission Resolution E-4805.”¹ CalCCA is a trade association
13 representing operational Community Choice Aggregation (“CCA”) programs in California.
14 CalCCA has been an active participant in this proceeding. Among other things, CalCCA
15 developed and submitted a presentation for the workshop held in this proceeding on December
16 12, 2017 (“CalCCA Presentation”). Also, in accordance with the *Administrative Law Judge’s*
17 *Ruling Entering Energy Division Staff Proposal Into The Record And Seeking Party Comments*,

¹ Scoping Memo at 1-2.

1 dated April 17, 2018 (“ALJ Ruling”), CalCCA submitted opening and reply comments on the
2 Energy Division staff proposal, attached as Appendix A to the ALJ Ruling (“Staff Proposal”),
3 and responses to specific questions pertaining to the Staff Proposal.

4 **II. TESTIMONY**

5 The ALJ Ruling expressly states that “presentations made at the December 12, 2017
6 workshop in this proceeding...are entered into the record of this proceeding.”² As noted above,
7 the CalCCA Presentation was served on parties to this proceeding, and was presented at the
8 December 12, 2017 workshop. As such, in accordance with the ALJ Ruling, CalCCA
9 understands that the CalCCA Presentation is part of the record of this proceeding, and may be
10 referenced in opening briefs, which are currently due on August 13, 2018.³ As a procedural
11 matter, however, and to more fully conform to the structure and schedule set forth in the ALJ
12 Ruling, CalCCA is submitting this prepared testimony, which largely reiterates positions
13 advanced by CalCCA in the CalCCA Presentation. For the avoidance of doubt, CalCCA hereby
14 incorporates by reference the CalCCA Presentation into this testimony. CalCCA anticipates that
15 it may also submit rebuttal testimony, which, as authorized in the Procedural Ruling, may be
16 submitted on or before July 18, 2018.

17 **A. The PCIA Proceeding**

18 The California Public Utilities Commission (“Commission”) is currently engaged in an
19 extensive examination “to review, revise, and consider alternatives to the ‘Power Charge

² ALJ Ruling at 2; Paragraph 1.

³ See Scoping Memo at 7.

1 Indifference Adjustment’ [(“PCIA”).”⁴ As noted in the PCIA Scoping Memo, “[t]he PCIA is a
2 mechanism adopted by the Commission...to ensure that when electric customers of the investor-
3 owned utilities [(“IOUs”)] depart from IOU service and receive their electricity from a non-IOU
4 provider, those customers remain responsible for costs previously incurred on their behalf by the
5 IOUs — but only those costs.”⁵ Included as a key part of the PCIA valuation methodology is the
6 so-called “market price benchmark,” which consists of various elements that are generally
7 intended to reflect the cost impact on the IOUs’ resource portfolio associated with departing
8 load.⁶ It is possible (even likely) that as part of the “[r]eview and possible modification of
9 current PCIA methodology,” the Commission may modify the market price benchmark,
10 including elements relating to resource adequacy (“RA”) attributes and renewable energy credits
11 (“RECs”).⁷ In an email to the service list for R.17-06-026, dated June 27, 2018, the assigned
12 administrative law judge stated that the assigned commissioner expects that a proposed decision
13 will be issued on PCIA matters by the end of July.

14 In the CalCCA Presentation, CalCCA stated that the “PCIA valuation methodology
15 should be used across all cost allocation processes, be they PCIA or policy-mandated
16 procurement.”⁸ Moreover, CalCCA stated that “[i]t is not efficient or appropriate for any party
17 to duplicate cost allocation or resource valuation analysis efforts across two proceedings

⁴ See *Scoping Memo and Ruling of Assigned Commissioner*, dated September 25, 2017 (as modified on November 22, 2017), in Rulemaking (“R.”)17-06-026 (“PCIA Scoping Memo”), at 2.

⁵ PCIA Scoping Memo at 2.

⁶ See PCIA Scoping Memo at 8.

⁷ See PCIA Scoping Memo at 15.

⁸ CalCCA Presentation at 4.

1 simultaneously.”⁹ CalCCA reaffirms these views. The PCIA valuation methodology should be
2 used across all cost allocation processes, including the valuation methodology used to determine
3 the Tree Mortality NBC.

4 **B. Energy and Ancillary Services**

5 As noted in the CalCCA Presentation, CalCCA understands that the IOUs intend to
6 “[s]ell energy and ancillary services into the [California Independent System Operator
7 (“CAISO”)] markets, and use the revenue to reduce the total tree mortality procurement costs
8 allocated to customers.”¹⁰ CalCCA believes that IOUs’ approach is reasonable and should be
9 adopted.

10 **C. Resource Adequacy**

11 CalCCA objects to the IOUs’ proposal to directly provide RA credits to Community
12 Choice Aggregators associated with the tree mortality power purchase agreements (“Tree
13 Mortality PPAs”).¹¹ As stated in the CalCCA Presentation, “[r]ather than direct distribution, the
14 value of RA credits should be monetized and included in the cost-benefit calculation [associated
15 with the Tree Mortality NBC].”¹² As part of the Tree Mortality NBC valuation, CalCCA
16 believes that “the current PCIA methodology for valuing RA [should be used] until that
17 methodology changes, whereupon the new methodology should be used.”¹³ That said, CalCCA is
18 amenable to using the new PCIA methodology for the full duration of the Tree Mortality PPAs,

⁹ CalCCA Presentation at 9.

¹⁰ CalCCA Presentation at 5.

¹¹ See the IOUs’ presentation at the December 12, 2017 workshop (“IOUs’ Presentation”) at
7.

¹² CalCCA Presentation at 6.

¹³ CalCCA Presentation at 6.

1 even with respect to RA capacity provided under the Tree Mortality PPAs for RA-months prior
2 to the Commission’s adoption of the new PCIA methodology. Because the IOUs’ tree mortality
3 procurement costs are currently being accounted for in memorandum accounts,¹⁴ and because a
4 decision on the new PCIA methodology is expected prior to a decision in this proceeding, the
5 Commission could apply the new PCIA methodology to the entire scope of the IOUs’ tree
6 mortality procurement costs. CalCCA is not opposed to this approach.

7 **D. Renewable Energy Credits**

8 CalCCA objects to the IOUs’ proposal to value RECs associated with the Tree Mortality
9 PPAs based on “Platt’s MW Daily mid-price for Category 1 resources in California.”¹⁵ The
10 value of RECs associated with the Tree Mortality PPAs should be based on the value set in the
11 PCIA proceeding. As previously stated by CalCCA, “[t]he current PCIA methodology should be
12 used for valuing RECs until that methodology is changed, whereupon the new methodology
13 should be used.”¹⁶ That said, as mentioned above, because a decision on the new PCIA
14 methodology is expected prior to a decision in this proceeding, the Commission could apply the
15 new PCIA methodology to the entire scope of the IOUs’ tree mortality procurement costs.
16 CalCCA is not opposed to this approach.

17 **E. Use of the Public Purpose Program Charge**

18 CalCCA understands that the IOUs intend to “[i]nclude the total net cost [of the Tree
19 Mortality PPAs] to benefitting customers [using] the Public Purpose Program [(“PPP”)]

¹⁴ See Resolution E-4805 at 17; Conclusions of Law 9 and 10.

¹⁵ IOUs’ Presentation at 8.

¹⁶ CalCCA Presentation at 7.

1 charge.”¹⁷ CalCCA does not oppose this approach, and generally believes that this approach “is
2 reasonable given that the financial amount at stake is not large enough to significantly change the
3 PPP.”¹⁸ On this note, CalCCA understands that the incremental increase to the current PPP
4 charge associated with the Tree Mortality NBC would be between 3 and 6 percent.¹⁹ That said,
5 as previously stated in the CalCCA Presentation, “[o]ther issues should be examined if additional
6 or other generation-related charges are proposed for inclusion in the PPP.”²⁰

7 **III. STATEMENT OF QUALIFICATION**

8 Hilary Staver is the Manager of Regulatory and Legislative Affairs at Silicon Valley
9 Clean Energy (“SVCE”), a Community Choice Aggregator serving carbon-free power to twelve
10 communities and the unincorporated areas of Santa Clara County. She is also the chair of the
11 CalCCA Regulatory Committee, coordinating CalCCA’s participation in proceedings at the
12 Commission and other regulatory agencies across the state. Prior to joining SVCE, Hilary
13 worked at Energy and Environmental Economics, Inc. (“E3”) on projects encompassing
14 greenhouse gas emissions modeling, cost allocation, rate design, distributed energy resource
15 valuation, transportation electrification, and a variety of other topics. She holds a Master of
16 Environmental Science degree from Yale University, where her research focused on adoption
17 processes and peer effects in the residential solar market, and a Bachelor of Science degree from
18 the University of Maryland, College Park.

¹⁷ CalCCA Presentation at 8. *See also* IOUs’ Presentation at 11 (“The Joint IOUs propose that the TM NBC’s net cost recovery be recovered via the PPP Charge rather than [new system generation charge].”).

¹⁸ CalCCA Presentation at 8.

¹⁹ *See* Attachment 1 (incorporating discovery responses from the IOUs).

²⁰ CalCCA Presentation at 8.

ATTACHMENT 1
TO
PREPARED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Southern California Edison
Tree Mortality NBC Joint Application A.16-11-005

DATA REQUEST SET A.16-11-005 CalCCA-SCE-001

To: CALCCA
Prepared by: Desiree Wong
Title: Project Manager
Dated: 06/22/2017

Question 09.a-f:

Please refer to Exhibit Joint IOU-01 at 5 in which the investor-owned utilities (“IOUs”) describe tree mortality non-bypassable charge cost recovery. (Unless otherwise noted, capitalized terms in this data request set shall refer to terms defined in Exhibit Joint IOU-01.)

9. Given current and expected costs in the BioMASSMA and BioRAMMA, respectively, and rate design assumptions contained in Exhibit Joint IOUs-01, please provide the expected “revised PPP rate,” as described in Exhibit Joint IOUs-01 at 10:4-5. Please also provide the following:
 - a. Assumed total contract costs. (*See* Exhibit Joint IOUs-01 at 4:13-18.)
 - b. Assumed RA capacity credit. (*See* Exhibit Joint IOUs-01 at 2.)
 - c. Assumed REC value. (*See* Exhibit Joint IOUs-01 at 3-4.)
 - d. Assumed value of energy. (*See* Exhibit Joint IOUs-01 at 4:5.)
 - e. Assumed value of ancillary services. (*See* Exhibit Joint IOUs-01 at 4:5.)
 - f. Incremental increase to the PPP rate associated with the TM NBC. (*See* Exhibit Joint IOUs-01 at 10:4-5.)

Response to Question 09.a-f:

9a. The forecast annual cost of SCE's Tree Mortality NBC contracts is \$59.277M

9b. The monthly NQC (MW) for SCE's Tree Mortality NBC contracts is as follows:

Generator Name	MW											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OGDEN POWER PACIFIC (CHINESE STATION)	16.84	16.73	16.52	12.21	12.06	16.92	16.17	16.19	15.85	16.12	14.15	17.85
RIO BRAVO FRESNO (AKA ULTRAPOWER)	23.38	8.9	23.39	23.8	15.32	23.63	23.87	23.92	19.15	23.89	21.83	23.63
Rio Bravo Rocklin	23.94	19.18	23.95	23.62	12.07	23.44	23.7	21.81	19.59	24.21	18.13	23.24

9c. The forecast annual REC value, calculated using the REC value adopted by the Commission in D.16-05-006, is \$4.934M.

9d. The forecast annual energy value, calculated using the energy market price benchmark

adopted by the Commission in D.16-12-054, is \$16.644M. SCE has used the Commission-adopted energy MPB in SCE's 2017 ERRRA to forecast the energy revenues for purposes of calculating the contracts' net costs and setting rates, but will record the actual energy revenues in the Tree Mortality Non Bypassable Charge (TM-NBC) balancing account. As described in Joint IOUs-01, any over- or under-collections in the TM-NBC BA will be amortized in rates the following year.

9e. There is no Commission-adopted prescriptive methodology for forecasting ancillary services revenue, so SCE has preliminarily included an assumed value of 0. However, actual ancillary revenues received will be recorded in the TM-NBC balancing account. As described in Joint IOUs-01, any over- or under-collections in the TM-NBC BA will be amortized in rates the following year.

9f. Based on the responses to 9a-9e above, SCE forecasts a \$0.00046/kWh increase to the system average Public Purpose Programs (PPP) rate, which results in a revised system average PPP rate of \$0.00793/kWh.

**PACIFIC GAS AND ELECTRIC COMPANY
Tree Mortality Non-Bypassable Charge
Application 16-11-005
Data Response**

PG&E Data Request No.:	CalCCA_001-Q09		
PG&E File Name:	TreeMortalityNon-BypassableCharge_DR_CalCCA_001-Q09		
Request Date:	June 21, 2017	Requester DR No.:	001
Date Sent:	July 7, 2017	Requesting Party:	California Community Choice Association (CalCCA)
PG&E Witness:	Donna Barry	Requester:	Scott Blaising

QUESTION 9

Given current and expected costs in the BioMASSMA and BioRAMMA, respectively, and rate design assumptions contained in Exhibit Joint IOUs-01, please provide the expected “revised PPP rate,” as described in Exhibit Joint IOUs-01 at 10:4-5. Please also provide the following:

- a. Assumed total contract costs. (See Exhibit Joint IOUs-01 at 4:13-18.)
- b. Assumed RA capacity credit. (See Exhibit Joint IOUs-01 at 2.)
- c. Assumed REC value. (See Exhibit Joint IOUs-01 at 3-4.)
- d. Assumed value of energy. (See Exhibit Joint IOUs-01 at 4:5.)
- e. Assumed value of ancillary services. (See Exhibit Joint IOUs-01 at 4:5.)
- f. Incremental increase to the PPP rate associated with the TM NBC. (See Exhibit Joint IOUs-01 at 10:4-5.)

ANSWER 9

The requested contract costs and PG&E’s proprietary forecasts for the value of revenue credits associated with REC, energy, and ancillary services value are confidential, market-sensitive information. Pursuant to a meet-and-confer teleconference with counsel for CalCCA on June 30, 2017, PG&E has agreed to provide this public version of the data response using public proxy assumptions. PG&E has used the following assumptions for each of the sub-parts listed above:

- a. **Contract costs:** The proxy values provided in Table 1 below are the product of MWh deliveries that are approximately equal to the expected contract deliveries times the weighted average TOD adjusted cost of Biomass resources contracted for in 2016 as published in the May 2017 Padilla Report published by the California Public Utilities Commission (the “Padilla Report”),¹ Table C-1 at page 25.

¹ CPUC. The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (Pursuant to Public Utilities Code Section 913.3), May 2017 (available at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisi)

- c. **REC Value:** The proxy value provided in Table 1 below approximates the expected REC value by multiplying renewable deliveries in MWh times a proxy REC value of \$10/MWh.
- d. **Energy Value:** The energy value provided in Table 1 below is the product of MWh deliveries times a brown market price benchmark (MPB). The brown MPB used in the calculation is based on the brown MPB included in PG&E's 2018 ERRA Forecast.
- e. **Ancillary Services:** Ancillary Service revenues are assumed to be zero as these contracts are not expected to be bid into the ancillary service market.

TABLE 1									
		[1]	[2]	Q.9.a	[4]	Q.9.d	Q.9.e	Q.9.c	
Row Labels	ERRA Label	Sum of MWhr Proxy	Sum of RPS Energy Proxy	Total Cost Proxy	Average Cost (\$/MWh)*	Energy Value = MWh x BrownMPB	AS Value	REC Value	Net Cost for PPP Allocation
						= column [1] x BrownPwr @ \$30.93	\$0	= column [2] x \$10/MWh	= [3] - [5] - [7]
Tree Mortality									
BioMass	Proxy Values	500,000	500,000	\$59,900,000	\$119.8	\$15,465,000	\$0	\$5,000,000	\$39,435,000
* Average Cost from Padilla Report, p. 25, Table C-1, Biomass Weighted Average TOD-Adjusted Price for Renewable Energy Contracts									

An excel version of this table can also be found in the attachment to this data request.

With respect to the RA capacity credit, PG&E notes that the RA capacity does not impact the incremental increase to the PPP rate since PG&E's proposal in the Application is to allocate the actual RA credits and not to monetize their value. Table 2 included in the attachment to this data request shows each contract's net qualifying capacity by month. However, the actual credit allocation to CCAs will be dependent on each CCAs' respective share of the coincident peak, adjusted on a monthly basis.

- f. Using the assumptions provided above, PG&E calculates that the incremental increase to the system average PPP rate would be approximately \$0.00047 per kWh. Table 3 included in the attachment to this data response provides additional detail on the incremental rate calculation, by revenue class.

Question 9 - Public

TABLE 1

Row Labels	[1] Sum of MW/hr Proxy	[2] Sum of RPS Energy Proxy	[3] Total Cost Proxy	[4] Average Cost (\$/MWh)*	[5] Energy Value = MWh x BrownMPB = column [1] x BrownPwr @ \$30.93	[6] AS Value	[7] REC Value = column [2] x \$10/MWh	[8] Net Cost for PPP Allocation = [3] - [5] - [7]
Tree Mortality Biomass	500,000	500,000	\$59,900,000	\$119.8	\$15,465,000	\$0	\$5,000,000	\$39,435,000
* Average Cost from Padilla Report, p. 25; Table C-1, Biomass Weighted Average IOD-Adjusted Price for Renewable Energy Contracts								

TABLE 2

O.9.b - NOC Value of Contracts (MWh-month)

Name	1/1/2018	2/1/2018	3/1/2018	4/1/2018	5/1/2018	6/1/2018	7/1/2018	8/1/2018	9/1/2018	10/1/2018	11/1/2018	12/1/2018
Burney Forest Products	22.87	20.60	21.72	19.22	20.13	23.05	23.39	23.34	23.02	21.17	20.95	21.82
Wheelabrator Shasta Energy Company Inc	0.00	24.15	25.47	22.54	23.60	27.02	27.43	27.36	26.99	24.82	24.56	25.58
Total	22.87	44.76	47.19	41.76	43.73	50.07	50.82	50.70	50.01	45.99	45.51	47.40

TABLE 3

O.9.f - PPP incremental rate impact

Incremental RRO for Tree Mortality NBC RRO:		\$39,435,000				
Allocation Class	12-CP Allocation	PPP Sales (kWh)	TW NBC RRO by Class	Incremental PPP Rate due to TW NBC (\$/kWh)	Current PPP Rate (\$/kWh)	% Increase due to TW NBC
Residential	42.4%	27,677,103,408	\$16,711,910	0.00060	0.01306	4.6%
Small L&P	10.1%	8,149,345,737	\$3,969,685	0.00049	0.01573	3.1%
Medium L&P	25.6%	22,748,314,837	\$10,082,244	0.00044	0.01375	3.2%
Streetlights	0.3%	333,766,682	\$125,179	0.00038	0.00855	4.4%
Standby	1.1%	759,790,221	\$425,101	0.00056	0.01885	3.0%
AG	6.2%	6,699,807,540	\$2,437,416	0.00036	0.01314	2.8%
E-20	14.4%	17,714,649,286	\$5,683,465	0.00032	0.01266	2.5%
Total or System Average	100.0%	84,082,777,713	\$39,435,000	0.00047	0.01346	3.5%

CalCCA DATA REQUEST
CalCCA-SDG&E-DR-01
JOINT IOU TREE MORTALITY NBC APPLICATION (A.16-11-005)
SDG&E RESPONSE



9. Given current and expected costs in the BioMASSMA and BioRAMMA, respectively, and rate design assumptions contained in Exhibit Joint IOUs-01, please provide the expected “revised PPP rate,” as described in Exhibit Joint IOUs-01 at 10:4-5. Please also provide the following:

a. Assumed total contract costs. (*See* Exhibit Joint IOUs-01 at 4:13-18.)

SDG&E Response:

SDG&E will respond to this question at such time as a Reviewing Representative has been identified and has signed the applicable Non-Disclosure Agreement.

b. Assumed RA capacity credit. (*See* Exhibit Joint IOUs-01 at 2.)

SDG&E Response:

This does not factor in the rate calculation. Per Joint IOUs-01 at 2, the RA capacity credit is shared among Load Serving Entities by share of coincident peak, adjusted on a monthly basis, which is consistent with the existing Cost Allocation Mechanism (“CAM”).

c. Assumed REC value. (*See* Exhibit Joint IOUs-01 at 3-4.)

SDG&E Response:

\$10.00/MWh

d. Assumed value of energy. (*See* Exhibit Joint IOUs-01 at 4:5.)

SDG&E Response:

**CalCCA DATA REQUEST
CalCCA-SDG&E-DR-01
JOINT IOU TREE MORTALITY NBC APPLICATION (A.16-11-005)
SDG&E RESPONSE**

SDG&E will respond to this question at such time as a Reviewing Representative has been identified and has signed the applicable Non-Disclosure Agreement.

- e. Assumed value of ancillary services. (See Exhibit Joint IOUs-01 at 4:5.)

SDG&E Response:

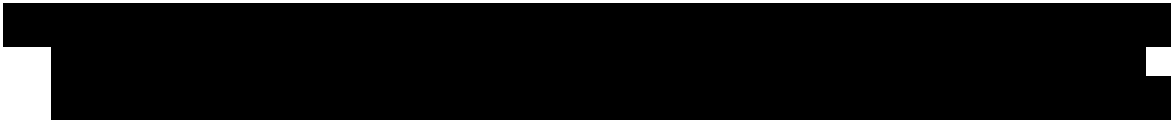
SDG&E will respond to this question at such time as a Reviewing Representative has been identified and has signed the applicable Non-Disclosure Agreement.

- f. Incremental increase to the PPP rate associated with the TM NBC. (See Exhibit Joint IOUs-01 at 10:4-5.)

SDG&E Response:

The table below provides the illustrative class-average PPP rate impacts associated with the recovery of the SDG&E forecasted annual TM NBC net costs.

ILLUSTRATIVE PPP RATE IMPACT DUE TO TM NBC				
	Class-Average PPP Rates (\$/kWh)			
	Current PPP Rate	Incremental PPP Rate Due to TM NBC	PPP Rate with TM NBC Recovery	% Increase Due to TM NBC
Residential				
PPP - class average rate	\$0.01060	\$0.00075	\$0.01135	7.1%
Small Commercial				
PPP - class average rate	\$0.01395	\$0.00074	\$0.01469	5.3%
Medium/Large Commercial & Industrial				
PPP - class average rate	\$0.01029	\$0.00061	\$0.01090	6.0%
Agricultural				
PPP - class average rate	\$0.01108	\$0.00037	\$0.01145	3.3%
Streetlighting				
PPP - class average rate	\$0.00650	\$0.00050	\$0.00700	7.7%
System Average				
PPP - class average rate	\$0.01077	\$0.00067	\$0.01144	6.2%
Notes:				
(1) Current PPP Rates reflect the class average PPP rates effective 3/1/17 per SDG&E Advice Letter 3034-E and 3034-E-A.				
(2) Incremental PPP Rates Due to TM reflect illustrative rates to recover TM NBC net costs based on the highest annual forecasted TM net costs and authorized kWh sales adopted in D.15-08-040.				



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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

Rulemaking 17-06-026
(Filed June 29, 2017)

**MARIN CLEAN ENERGY AND SONOMA CLEAN POWER
AUTHORITY NOTICE OF EX PARTE COMMUNICATION**

Nathaniel Malcolm
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Neal Reardon
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June 28, 2018

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

Order Instituting Rulemaking to Review,
Revise, and Consider Alternatives to the
Power Charge Indifference Adjustment

Rulemaking 17-06-026
(Filed June 29, 2017)

**MARIN CLEAN ENERGY AND SONOMA CLEAN POWER
AUTHORITY NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rules 8.2 and 8.4 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure and Public Utilities Code (“Cal. P.U. Code”) Section 1701.1 and 1701.3(h)(2), Marin Clean Energy (“MCE”) and Sonoma Clean Power Authority (“SCPA”) hereby give notice of the following *ex parte* communication.

Neal Reardon, SCPA Director of Regulatory Affairs, initiated the communication on behalf of SCPA and MCE. The meeting was telephonic and took place on June 28, 2018 from approximately 10:00 a.m. to 10:20 a.m. The meeting included oral and written communications. The attendees included: Joanna Gubman, Advisor to Commissioner Randolph; Nathaniel Malcolm, Policy Counsel for MCE; and Neal Reardon, Directory of Regulatory Affairs for SCPA. Due to the breadth of the topics discussed during this *ex parte* communication, this notice is being served on the service lists for the above-captioned proceeding and the Integrated Resource Planning (“IRP”) proceeding, Rulemaking (“R.”) 16-02-007.

MCE and SCPA used written materials during the *ex parte* communication. Because the *ex parte* was telephonic, Neal Reardon of SCPA provided the written materials to Joanna Gubman via email the morning of the *ex parte* communication, June 28, 2018 at approximately 8:42 a.m.

The written materials are attached to this notice as Attachment A. The email providing the written materials to Joanna Gubman is attached as Attachment B.

MCE and SCPA voiced their position that the Joint Utilities' Green Allocation Mechanism ("GAM") violates statute by allocating products to Community Choice Aggregators ("CCA"). The involuntary allocation of Renewable Energy Credits ("RECs") via the GAM would also severely interfere with a CCA's statutory authority to be solely responsible for procurement decisions on behalf of the local communities and customers it serves. MCE and SCPA also communicated that the REC allocations would represent an illegal cost shift to CCA customers, particularly in the case of CCAs that have procured long-term to comply with state policy goals and Commission rules. This cost shift would result because the GAM allocation would force "devalued" RECs on CCAs, while allocating to CCAs and their customers the price of a fully bundled REC.

MCE and SCPA addressed the California Community Choice Association's ("CalCCA") voluntary Staggered Portfolio Auction ("SPA") as a way for all Load Serving Entities ("LSE"), including the Investor Owned Utilities ("IOU") to acquire the Renewable Portfolio Standard ("RPS") resources needed to serve their forecasted loads and meet, or voluntarily exceed, RPS requirements. The SPA could accomplish this result without forcing particular LSEs to be involuntarily long on RPS. It would also maximize the value of these resources by allocating them to the LSEs that value them the most. In this context, MCE and SCPA contrasted CalCCA's approach to the Joint Utilities' approach. MCE and SCPA emphasized that CalCCA's proposal seeks to maximize value and reduce costs for bundled and unbundled customers, whereas the Joint Utilities' approach does nothing to reduce costs passed through to customers.

MCE and SCPA voiced concerns that the GAM, unlike the SPA, would not provide CCAs the underlying energy associated with the allocated GAM RECs. In addition to devaluing the

allocated RECs, the after-the-fact allocation of RECs would force CCAs to rely heavily on spot market purchases to meet their daily and hourly loads, despite their long-term procurement activities. MCE and SCPA also broached concerns that the GAM is inconsistent with the forecasting approach used in the IRP proceeding and that it would interfere with the Clean Net Short (“CNS”) methodology adopted recently in the IRP proceeding, R.16-02-007.

MCE and SCPA also indicated that they have no need for the Resource Adequacy (“RA”) allocations under the GAM because both CCAs are already meeting the Commission’s RA requirements and executing long-term RA commitments.

MCE and SCPA provided a graphical presentation of the GAM’s projected effects on established CCAs with developed, long-term procurement plans. Specifically, MCE and SCPA illustrated that both CCAs are currently exceeding annual RPS requirements and are projected to meet and exceed RPS requirements through 2030 without GAM allocations. Superimposing forecasted GAM allocations on MCE’s current long-term portfolio would put MCE’s portfolio above 90% RPS in 2019 and over 100% RPS in 2024; superimposing GAM allocations on SCPA’s portfolio would put its portfolio at 73% RPS in 2019 and nearly 70% RPS in 2024. MCE and SCPA expect this trend to continue through 2030 if the GAM were approved. MCE and SCPA also voiced concerns that the GAM allocations would impede CCAs’ ability to invest in new build in California.

MCE and SCPA emphasized they are already positioned to meet their respective long-term RPS contracting requirements under Senate Bill 350 (Cal. P.U. Code Section 399.13(b)) starting in 2020 and continuing through 2030 without GAM allocations. Moreover, MCE and SCPA forecast that GAM allocations will come at a cost of approximately \$169 million for MCE in 2019 and approximately \$79 million for SCPA in 2019.

MCE and SCPA also indicated that forcing MCE and SCPA to be excessively long on RPS would potentially bring Pacific Gas and Electric Company (“PG&E”) and Southern California Edison Company (“SCE”) well under RPS compliance.

Finally, MCE and SCPA challenged the Joint Utilities’ claims that the GAM is immediately implementable. This challenge is based in part on the GAM being inconsistent with the CNS methodology, the IRP, greenhouse gas accounting protocols, and rules for Portfolio Content Category treatment.

Respectfully submitted,

/s/ Nathaniel Malcolm

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/s/ Neal Reardon

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June 28, 2018

ATTACHMENT A
WRITTEN MATERIALS



Local. Renewable. Ours.



Meeting with Commissioner Randolph's Office Power Charge Indifference Adjustment (R.17-06-026)

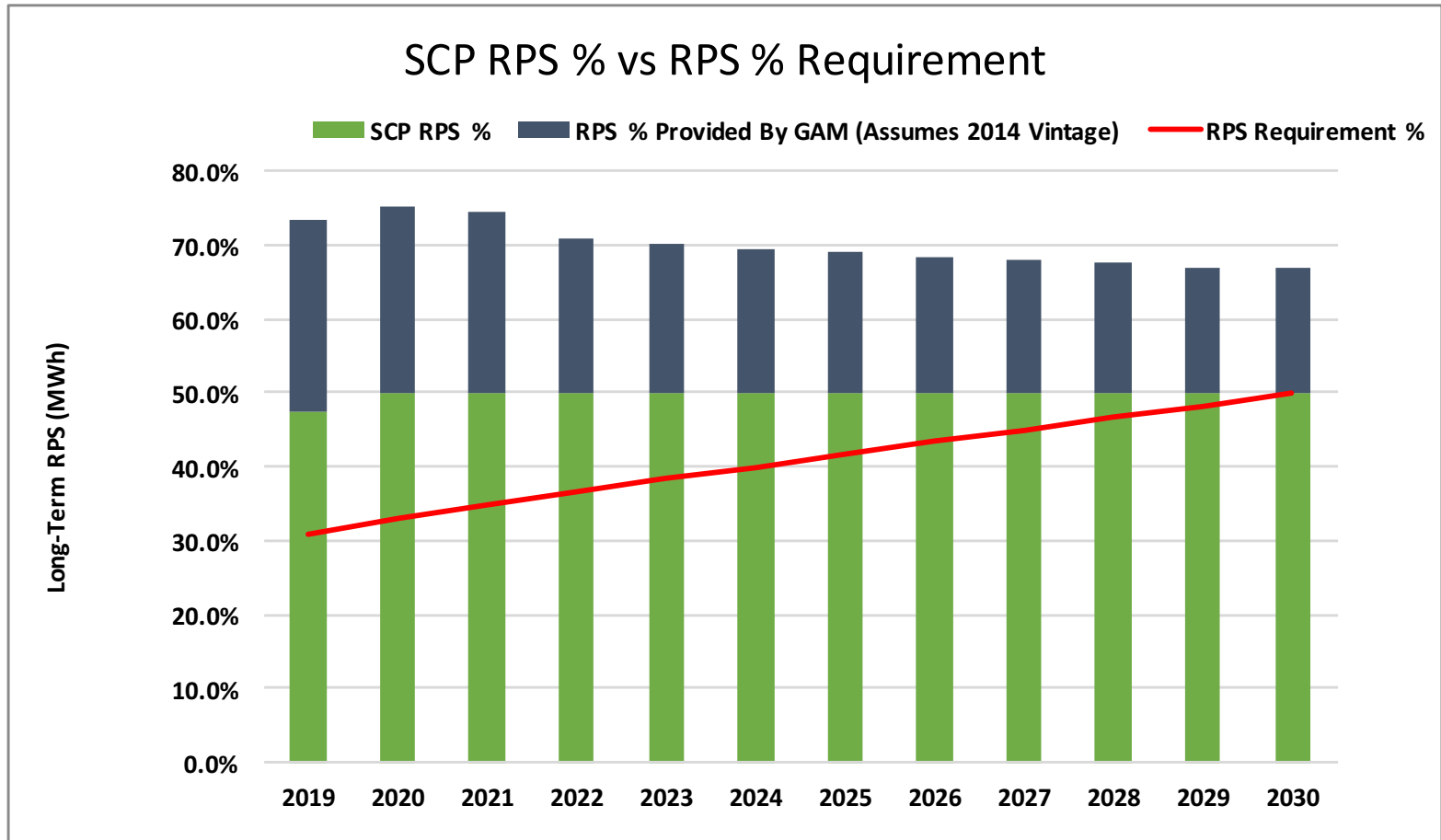
Neal Reardon, Sonoma Clean Power
Nathaniel Malcolm, MCE Clean Energy
June 28, 2018

GAM is not legal, efficient, equitable, practical, or cost-effective

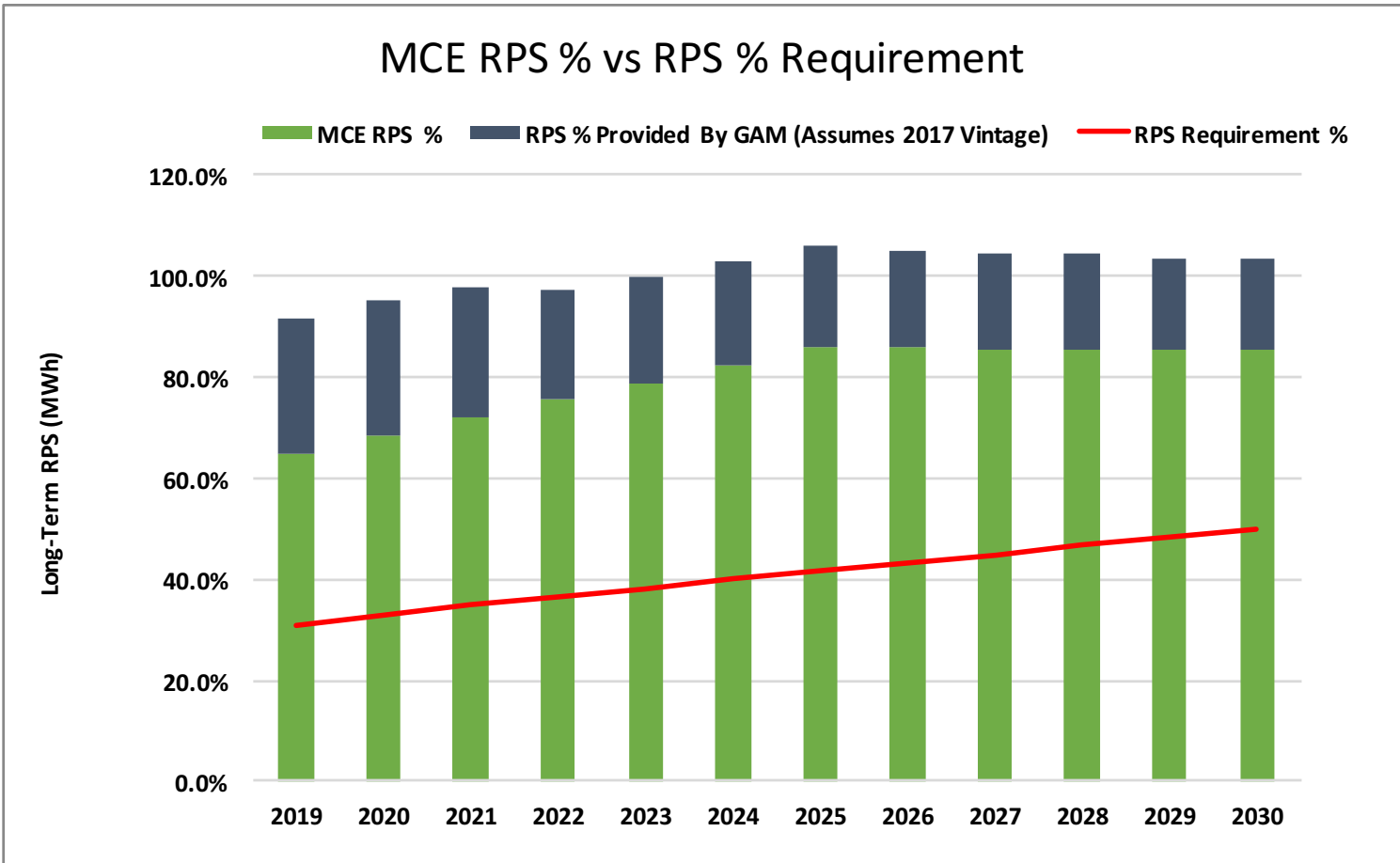
- **Illegal:** PU Code provides for allocation of net unavoidable costs, not *products*
- **Inefficient:** Dumps RECs after-the-fact, leaving CCAs unable to plan or hedge, would eliminate RPS procurement by CCAs and increase GHGs
- **Inequitable:** IOUs would control majority of assets while serving only 15% of load, creating anti-competitive scenario and continued litigation
- **Impractical:** Existing CCAs have made long-term plans and procured accordingly, consistent with statute
 - GAM would cause most harm to mature CCAs with long-term contracts
- **Expensive:** 2019 GAM Allocations would represent
 - \$79M for SCP and \$169M for MCE
 - \$30.72/MWh; ~50% increase over retail generation rates

Impact of GAM on Existing CCA: SCP

>75% RPS in 2020 vs. 33% Requirement

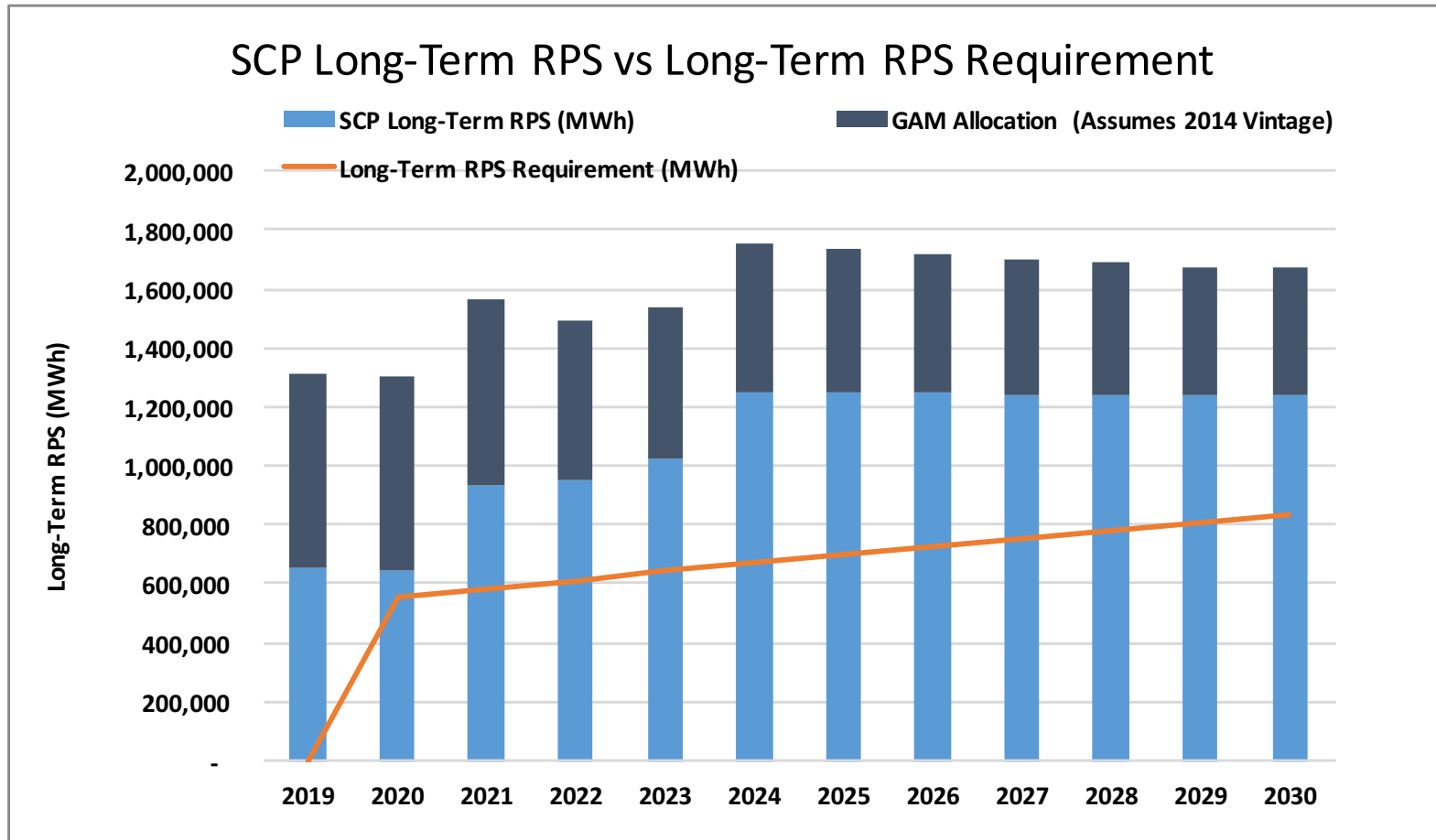


Impact of GAM on Existing CCA: MCE >100% RPS in 2023 and onwards



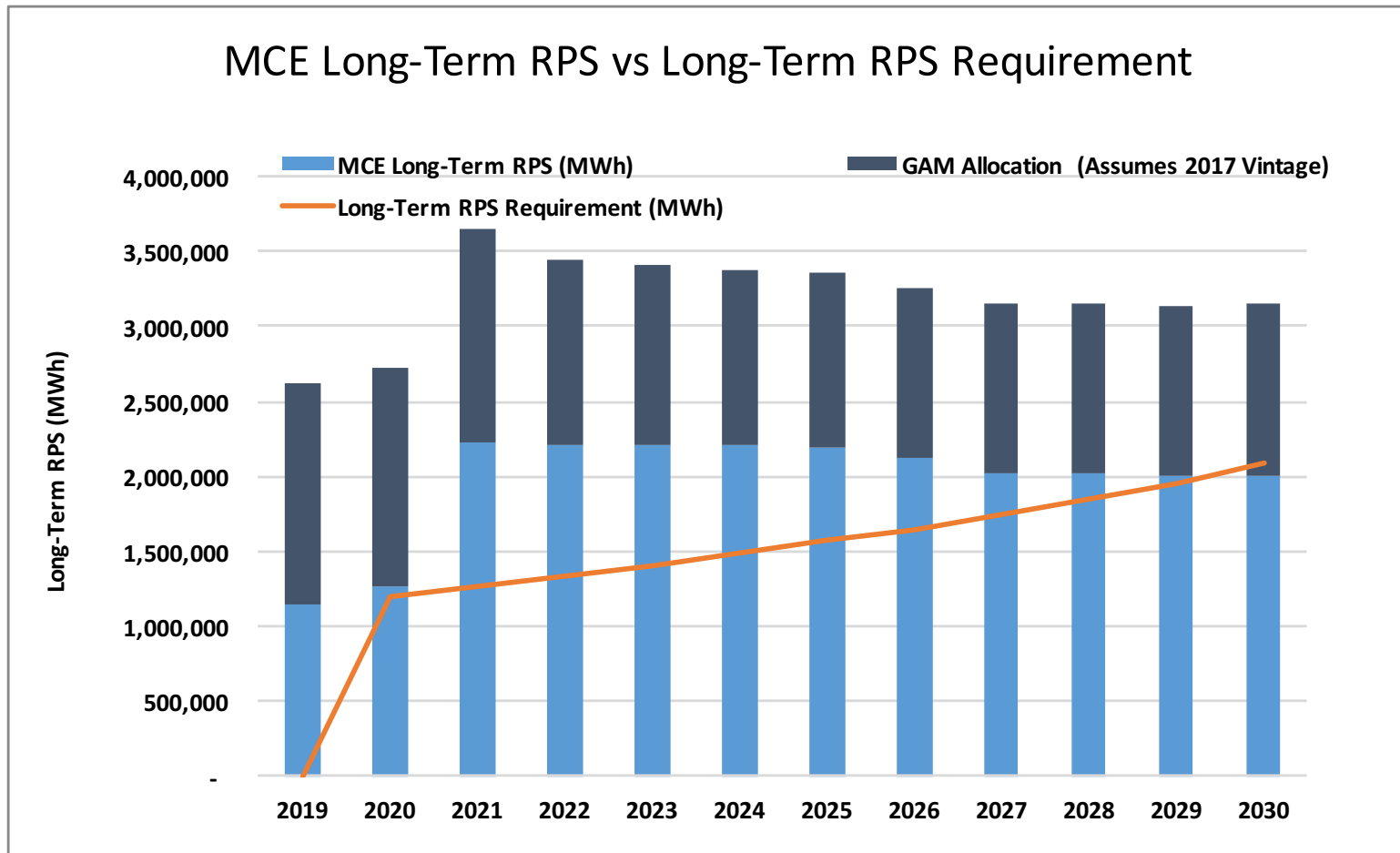
Impact of GAM on Existing CCA: SCP

>930 GWH Long-term RPS in 2021 vs. 584 Requirement



Impact of GAM on Existing CCA: MCE

>2,222 GWH Long-term RPS in 2021 vs. 1,261 Requirement



By Comparison: Impact of GAM on IOU Portfolios 2025 Sample year

RPS-Eligible Energy (GWh)
Supply/Demand Illustration

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	12-Yr Total
IOU RPS % (Pre-GAM Allocation) (NOTE: REFLECTS CURRENT-YEAR PROCUREMENT ONLY SO IGNORES BANK IMPACTS)													
PG&E	44%	43%	42%	36%	35%	34%	33%	32%	31%	31%	29%	29%	35%
SCE	49%	53%	55%	54%	53%	52%	51%	50%	46%	43%	43%	42%	49%
Subtotal	47%	48%	48%	45%	44%	43%	42%	41%	39%	37%	36%	35%	42%

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	12-Yr Total
IOU RPS % (Post-GAM Allocation) (NOTE: REFLECTS CURRENT-YEAR PROCUREMENT ONLY SO IGNORES BANK IMPACTS)													
PG&E	27%	26%	25%	22%	21%	20%	20%	19%	19%	18%	18%	17%	21%
SCE	30%	32%	33%	32%	32%	31%	31%	30%	28%	26%	26%	25%	29%
Subtotal	28%	29%	29%	27%	26%	26%	25%	25%	23%	22%	22%	21%	25%

Load Serving Entity	2025 RPS (%)	2025 Requirement (%)
PG&E	20	42
SCE	31	42
Sonoma Clean Power	69	42
MCE Clean Energy	106 %	42

Note: Assumes 40% load departures, does not include confidential banking data

Appendix A: GAM SCP Figures

Appendix: GAM Impact on Sonoma Clean Power												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast load MWh	2,557,467	2,580,792	2,583,373	2,578,206	2,573,050	2,570,477	2,567,906	2,565,338	2,562,773	2,560,210	2,557,650	2,555,092
RPS Requirement %	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%
RPS requirement MWh	792,815	851,661	899,014	941,045	985,478	1,028,191	1,070,817	1,110,792	1,153,248	1,195,618	1,235,345	1,277,546
Long term RPS requirement %	0	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Long-Term RPS Requirement (MWh)	-	553,580	584,359	611,679	640,561	668,324	696,031	722,014	749,611	777,152	802,974	830,405
SCP RPS %	47.6%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
SCP RPS % with GAM	73.5%	75.4%	74.5%	70.9%	70.0%	69.5%	69.2%	68.3%	67.9%	67.7%	67.0%	66.8%
RPS % Provided By GAM (Assumes 2014 Vintage)	25.9%	25.4%	24.5%	20.9%	20.0%	19.5%	19.2%	18.3%	17.9%	17.7%	17.0%	16.8%
GAM Allocation (Assumes 2014 Vintage)	661,963	654,456	634,147	538,815	514,647	500,361	491,824	469,557	457,710	452,833	433,934	430,032
SCP RPS procured MWh	1,216,573	1,191,365	800,805	799,815	798,838	799,056	796,883	795,917	356,946	355,988	355,033	354,080
SCP RPS under negotiation/planned MWh			287,008	313,037	382,027	451,018	450,068	449,122	448,181	447,245	446,314	445,387
SCP existing contract re-up MWh									438,000	438,000	438,000	439,200
SCP short term RPS true up MWh		99,031	203,874	176,251	105,660	35,165	37,003	37,630	38,259	38,872	39,478	38,879
SCP Total RPS MWh	1,216,573	1,290,396	1,291,686	1,289,103	1,286,525	1,285,238	1,283,953	1,282,669	1,281,387	1,280,105	1,278,825	1,277,546
SCP Total RPS MWh with GAM	1,878,536	1,944,852	1,925,834	1,827,918	1,801,172	1,785,600	1,775,777	1,752,226	1,739,096	1,732,939	1,712,759	1,707,578
SCP Long-Term RPS % with GAM	165.6%	152.6%	174.0%	158.8%	156.0%	170.2%	162.4%	154.4%	147.5%	141.7%	135.5%	130.6%
GAM Allocation (Assumes 2014 Vintage)	661,963	654,456	634,147	538,815	514,647	500,361	491,824	469,557	457,710	452,833	433,934	430,032
SCP long term RPS procured MWh	650,891	645,321	643,125	642,135	641,158	799,056	796,883	795,917	356,946	355,988	355,033	354,080
SCP long term RPS under negotiation/planned MWh			287,008	313,037	382,027	451,018	450,068	449,122	448,181	447,245	446,314	445,387
SCP existing contract re-up MWh									438,000	438,000	438,000	439,200
SCP Long-term RPS (MWh)	650,891	645,321	930,133	955,172	1,023,185	1,250,074	1,246,951	1,245,039	1,243,127	1,241,233	1,239,347	1,238,667
SCP Long-Term RPS MWh with GAM	1,312,854	1,299,777	1,564,280	1,493,987	1,537,832	1,750,435	1,738,775	1,714,596	1,700,837	1,694,067	1,673,281	1,668,699

Appendix B: GAM MCE Figures

Appendix: GAM Impact on MCE Clean Energy												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast Load MWh	5,512,252	5,544,283	5,579,058	5,618,200	5,664,714	5,718,596	5,781,807	5,857,733	5,950,241	6,072,436	6,222,491	6,408,290
RPS Requirement %	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%
RPS Requirement MWh	1,708,798	1,829,613	1,941,512	2,050,643	2,169,586	2,287,439	2,411,014	2,536,398	2,677,609	2,835,827	3,005,463	3,204,145
Long Term RPS Requirement %	0	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
Long-Term RPS Requirement (MWh)	-	1,189,249	1,261,983	1,332,918	1,410,231	1,486,835	1,567,159	1,648,659	1,740,446	1,843,288	1,953,551	2,082,694
MCE RPS %	65.1%	68.7%	72.1%	75.5%	78.9%	82.3%	85.7%	85.7%	85.7%	85.7%	85.7%	85.6%
MCE RPS % with GAM	91.9%	95.0%	97.8%	97.5%	100.0%	102.8%	105.9%	105.0%	104.6%	104.4%	103.6%	103.4%
RPS % Provided By GAM (Assumes 2017 Vintage)	26.8%	26.3%	25.7%	22.0%	21.1%	20.5%	20.2%	19.3%	18.9%	18.7%	18.0%	17.8%
GAM Allocation (Assumes 2017 Vintage)	1,476,113	1,459,800	1,432,010	1,235,976	1,194,093	1,174,074	1,168,009	1,132,890	1,123,177	1,135,313	1,118,077	1,141,808
MCE RPS Procured MWh	2,014,473	1,824,289	2,251,755	2,245,225	2,239,705	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE RPS under Negotiation/Planned MWh	1,573,319	1,983,940	1,770,780	1,996,979	2,230,333	2,501,718	2,756,384	2,903,068	3,075,975	3,185,048	3,318,739	3,481,734
MCE Existing Contract Re-Up MWh												
MCE Short Term RPS True-Up MWh												
MCE Total RPS MWh	3,587,792	3,808,229	4,022,535	4,242,204	4,470,038	4,706,813	4,954,972	5,020,358	5,098,805	5,202,425	5,329,672	5,487,230
MCE Total RPS MWh with GAM	5,063,905	5,268,029	5,454,544	5,478,181	5,664,131	5,880,887	6,122,982	6,153,248	6,221,982	6,337,738	6,447,749	6,629,038
MCE Long-Term RPS % with GAM	153.7%	149.2%	188.2%	168.3%	156.9%	147.7%	139.6%	128.1%	117.5%	111.2%	104.1%	98.2%
GAM Allocation (Assumes 2017 Vintage)	1,476,113	1,459,800	1,432,010	1,235,976	1,194,093	1,174,074	1,168,009	1,132,890	1,123,177	1,135,313	1,118,077	1,141,808
MCE Long Term RPS Procured MWh	1,150,373	1,270,189	2,222,655	2,216,125	2,210,605	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE Long Term RPS under Negotiation/Planned MWh												
MCE Existing Contract Re-Up MWh												
MCE Long-Term RPS (MWh)	1,150,373	1,270,189	2,222,655	2,216,125	2,210,605	2,205,094	2,198,588	2,117,290	2,022,830	2,017,377	2,010,933	2,005,496
MCE Long-Term RPS MWh with GAM	2,626,486	2,729,989	3,654,665	3,452,102	3,404,697	3,379,169	3,366,597	3,250,180	3,146,007	3,152,690	3,129,010	3,147,304

ATTACHMENT B
COMMUNICATION EMAIL

Subject: Slides for our 10am call



Neal Reardon <nreardon@sonomacleanpower.org>
to Gubman, Joanna, Smith, Mark A., nmalcolm@mcecleanenergy.org

8:42 AM (7 hours ago)

You are viewing an attached message. MCE Clean Energy Mail can't verify the authenticity of attached messages.

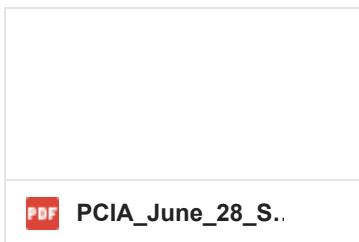
Hi Joanna,

Attached are slides we'd like to use to guide our conversation at 10am.

Until then,
Neal

Neal Reardon | [Sonoma Clean Power](#)
Director of Regulatory Affairs
www.SonomaCleanPower.org
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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric
Company for Adoption of Electric Revenue
Requirements and Rates Associated with its
2019 Energy Resource Recovery Account
(ERRA) and Generation Non-Bypassable
Charges Forecast and Greenhouse Gas
Forecast Revenue and Reconciliation
(U 39 E)

Application 18-06-001
(Filed June 1, 2018)

**PROTEST OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN
ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA
CLEAN ENERGY, PIONEER COMMUNITY ENERGY, AND SONOMA
CLEAN POWER AUTHORITY TO APPLICATION OF PACIFIC GAS
AND ELECTRIC COMPANY FOR 2019 ENERGY RESOURCE
RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE
CHARGES FORECAST AND
GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION**

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July 5, 2018

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

Application of Pacific Gas and Electric
Company for Adoption of Electric Revenue
Requirements and Rates Associated with its
2019 Energy Resource Recovery Account
(ERRA) and Generation Non-Bypassable
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CLEAN ENERGY, PIONEER COMMUNITY ENERGY, AND SONOMA
CLEAN POWER AUTHORITY TO APPLICATION OF PACIFIC GAS
AND ELECTRIC COMPANY FOR 2019 ENERGY RESOURCE
RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE
CHARGES FORECAST AND
GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION**

I. INTRODUCTION

In accordance with Rule 2.6 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure (“Commission Rules”), East Bay Community Energy (“EBCE”), Marin Clean Energy (“MCE”), Monterey Bay Community Power (“MBCP”), Peninsula Clean Energy (“PCE”), Pioneer Community Energy (“Pioneer”), and Sonoma Clean Power Authority (“SCP”) (collectively “the Joint CCAs”)¹ submit the following protest to the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account and*

¹ The above-mentioned CCAs respectfully request independent party status as signatories to this protest.

Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed on June 1, 2018 (“Application”).² Pacific Gas and Electric Company’s (“PG&E”) Application would result in bundled rate decreases. However, they would result in an average increase in the Power Charge Indifference Adjustment (“PCIA”) of about 10% and an average decrease in the generation rate of between 13-16%. While the reductions in overall rates are welcome, the increase in PCIA needs to be more closely examined, reviewed, and validated to ensure fair competition.

PG&E’s Application currently does not provide sufficient evidence that its proposed rate changes are justified. PG&E has not sufficiently demonstrated that it adequately managed its portfolio to ensure that only unavoidable above-market costs are passed through to departing load customers via the PCIA.³ State law only authorizes PG&E to pass on to CCA customers through the PCIA costs that are unavoidable.⁴ Absent a transparent showing in this regard, the Joint CCAs are subject to a significant competitive disadvantage relative to PG&E, in violation of Senate Bill 790.⁵ Moreover, lack of transparency and accountability renders the Joint CCAs’ customers blind to cost shifts that are contrary to statute.⁶ The Joint CCAs ask the Commission to carefully evaluate PG&E’s proposed changes to the PCIA and the generation rate, and to establish metrics that will assist the Commission and interested stakeholders in assessing PG&E’s portfolio management practices going forward.

² PG&E’s Application first appeared in the Daily Calendar on June 4, 2018. As such, this protest is timely pursuant to Rule 2.6(a) of the Commission’s Rules.

³ See Cal. Pub. Util. Code Section 366.2.

⁴ See Cal. Pub. Util. Code Section 366.2(f)(2).

⁵ See Section 2(h) of Senate Bill (SB) 790 (Leno, 2011).

⁶ See Cal. Pub. Util. Code Section 366.3.

II. JOINT CCAs' INTEREST

Each of the Joint CCAs is governed by a Board of Directors comprised of elected officials that represent the individual cities and counties the CCA serves or an elected City Council.⁷ CCAs must comply with the same mandates applicable to all load serving entities, including the Renewables Portfolio Standard (“RPS”) requirements, Resource Adequacy requirements, and greenhouse gas emission reduction requirements.⁸ CCAs also must meet local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation. CCAs have and continue to meet this demand while offering affordable, competitive, and stable rates despite the historical increase and volatility of the PCIA. While CCAs agree that state law requires their customers to pay unavoidable above-market costs of commitments made on their behalf, CCAs are concerned that PG&E’s proposed PCIA is not limited to the costs permitted by state law. CCAs are also concerned about the opaque process by which the PCIA is calculated and determined.

As advocates for their customers who will be subject to the PCIA, CCAs have a particular interest in the outcome of this proceeding. To the extent PG&E has not demonstrated that the costs included in the PCIA are unavoidable, the changes PG&E seeks are not in accordance with state law.

III. GROUNDS FOR PROTEST

PG&E has not sufficiently shown that the costs it seeks to include in the PCIA are limited to unavoidable costs. In particular, PG&E has not demonstrated that its portfolio management practices maximize the value of PG&E’s portfolio and reduce above-market costs. The Joint

⁷ See Pub. Util. Code Section 366.2.

⁸ See Cal. Pub. Util. Code Section 399.12(j)(2).

CCAs ask the Commission to address PG&E’s portfolio management practices and undertake an evaluation beyond a limited review of PG&E’s compliance with the “least-cost-best-fit” dispatch model. While bidding behavior is an important aspect of portfolio management, choosing which resources to keep online and which to retire or dispose of is more impactful. For example, PG&E’s continued operation of the Diablo Canyon Power Plant (“Diablo Canyon”) affects PCIA rates as proposed by PG&E, although continuing to operate Diablo Canyon is an avoidable cost. This plant is not needed for compliance with environmental policies, nor does it provide local or flexible capacity. Diablo Canyon’s going forward costs exceed market prices, and the above market costs of operating Diablo Canyon are included in the PCIA as well as bundled generation rates. Because these costs could be avoided by ceasing to operate Diablo Canyon, or at least implementing season dispatch, they are not unavoidable and are hence improperly included in the PCIA. The role of the Commission is to address these types of questions to protect ratepayers.

While the general structure of the PCIA is the subject of Rulemaking 17-06-026, the propriety of PG&E’s proposed increase in the 2019 PCIA is at issue in this proceeding. Therefore, the Joint CCAs seek to ensure that the revenue requirements PG&E proposes through the Energy Resource Recovery Account (“ERRA”) process are fairly and transparently determined and weighed against the Commission’s mandate by the California legislature “to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers.”⁹ To do so requires a comprehensive evaluation of PG&E’s portfolio management practices.

⁹ See Section 2(h) of Senate Bill (SB) 790 (Leno, 2011).

To date the Commission has not afforded interested parties an adequate forum in which to examine PG&E's portfolio management practices. In PG&E's 2018 ERRA proceeding, Application ("A.") 17-06-005, the Commission's Scoping Memo and Ruling determined that "PG&E's administration of procurement contracts, as well as management of procurement portfolios are outside the scope of an ERRA forecast proceeding and best addressed in the compliance phase."¹⁰ Yet, the Assigned Commissioner's Scoping Memo and Ruling in PG&E's most recent ERRA compliance proceeding (A.18-02-015) indicated that PG&E's contract management practices involved PG&E's bundled procurement plan.¹¹ As such, the Commission ruled that the ERRA compliance proceeding "was not the appropriate procedural venue to address changes to the bundled procurement plan" and that challenges to PG&E's contract management practices should be pursued via a Petition for Modification of the decision approving PG&E's bundled procurement plan.¹² The bundled procurement plans, however, are not portfolio management plans. The procurement plans only assess new resource *acquisition*, but do not evaluate acquired resource *disposition*. PG&E's resource management practices are squarely within the scope of this proceeding because PG&E's revenue request is based on how their portfolio performs in response to changing market and regulatory conditions.

In addition, the Commission should use this forecast proceeding to develop clear metrics beyond the traditional least-cost-dispatch model which focuses solely on resource operation. In fact, this focus ignores the least-cost best-fit metrics used to acquire many of these resources. These metrics can be referenced in PG&E's annual ERRA compliance proceeding to determine

¹⁰ *Scoping Memo and Ruling of Assigned Commissioner*, Application 17-06-005, filed August 4, 2017 at 3.

¹¹ *Assigned Commissioner's Scoping Memo and Ruling*, Application 18-02-015, filed May 14, 2018 at 3-4.

¹² *Id.*

whether PG&E is in fact optimizing its portfolio adequately to minimize costs for all ratepayers.

These metrics could include:

- Forecasted revenue recovery outside of CAISO DA/RT/AS markets for UOG and PPA resources;
- Assessment of the opportunities for PPA sales against forecasted PPA costs and market prices;
- Assessment of PPA termination costs vs. continued acceptance of deliveries;
- Assessment of PPA curtailment savings vs. continued acceptance of deliveries at forecasted amounts; and
- Calculation and updating of the hedge value identified but not quantified in PG&E's RPS Procurement Plan to determine if the management of the portfolio optimizes that hedge value.

For the above-mentioned reasons, PG&E's Application should be closely scrutinized in this proceeding. The Commission should specifically focus on PG&E's portfolio management practices and how those practices may lead to increased costs for all ratepayers. This proceeding is an opportunity for the Commission to demonstrate leadership by proactively outlining how compliance with the CPUC's Procurement Policy Manual¹³ should be demonstrated.

IV. RULE 2.6(d) COMPLIANCE

A. Proposed Category

PG&E appropriately categorizes the instant proceeding as "ratesetting."

B. Need for Hearing

Due to the significant anti-competitive impacts on CCAs that may result from the approval of PG&E's requested revenue requirement and contract management practices,

¹³ California Public Utilities Commission AB 57, AB 380, SB 1078 Procurement Policy Manual. Available online at: <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10906>

evidentiary hearings will be necessary. The factual record will need to be explored in detail to determine whether PG&E's proposed revenue requirements are accurate, reasonable, and represent only the unavoidable above-market costs of PG&E's portfolio.

C. Proposed Schedule

The Joint CCAs do not propose any revisions to the schedule as proposed by PG&E.

V. SERVICE LIST

Filings and other communications to this proceeding should be served on the following individuals:

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IV. CONCLUSION

The Joint CCAs thank Commissioner Guzman Aceves and Assigned Administrative Law Judge Eric Wildgrube for their thoughtful consideration of this protest and the issues detailed herein.

Respectfully submitted,

/s/ _____

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July 5, 2018



Diversification is Not Deregulation

CCAs have procurement autonomy, which diversifies the retail energy market and stimulates competition and innovation in electricity generation. CCAs are also robustly regulated by:

California Public Utilities Commission (CPUC)

- » Statewide standard compliance: renewable portfolio standards (RPS), resource adequacy (RA), storage requirements, integrated resource planning (IRP)

Western Renewable Energy Generation Information System (WREGIS)

- » Renewable energy credits retirement reporting

California Independent System Operator (CAISO)

- » Flexible capacity needs reporting

California Energy Commission (CEC)

- » Integrated energy policy report demand forecasts and resource plans

Boards of Local Government Elected Officials:

- » CCAs hold board meetings open to the public with notice requirements under the **Brown Act**. The meetings include discussion and decisions on management, policy, and procurement, such as:
 - » Power purchase agreements (PPAs), vendor contracts, and public work activities.
 - » Key planning documents such as MCE’s integrated resources plan (IRP).
- » Disclose non-confidential documents at the request of a member of the public as required under the **California Public Records Act**.
- » Are accountable to the community and serve over 80% of the customers in their service areas.

Disclaimer: This is intended to serve as a sample of CCA compliance obligations.

CCAs Drive State Goals

1) DECARBONIZATION

MCE has always exceeded the state’s minimum requirement for renewable power and currently provides 50-100% renewable power and 80-100% greenhouse gas-free power to all customers.

2) RELIABILITY

MCE has invested more than \$1.6 billion to build 813 megawatts of new renewable projects in California.

3) AFFORDABILITY

MCE maintains affordable rates, often lower than PG&E even when counting utility exit fees.

The Enduring Role of the IOUs

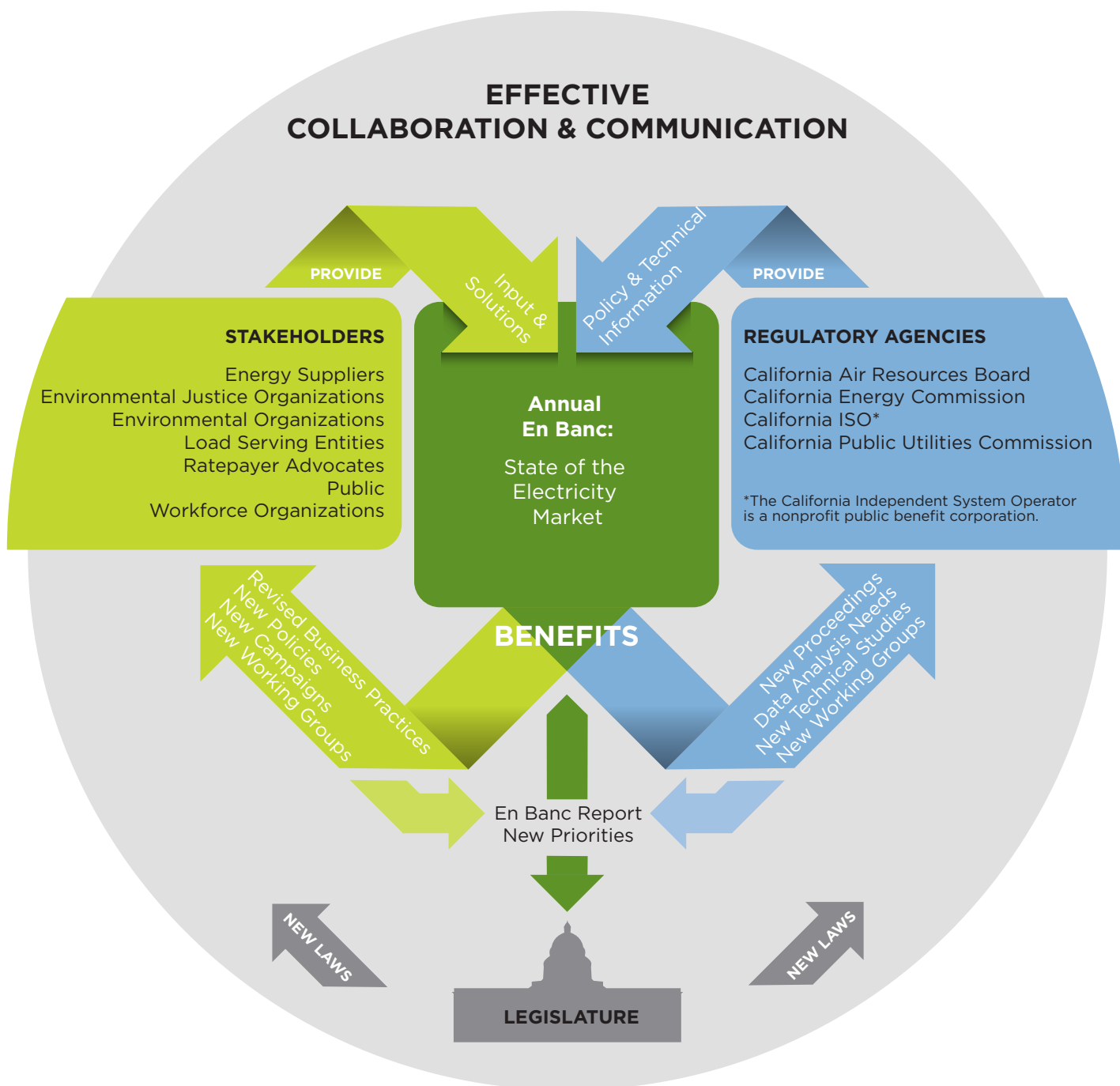
The CPUC estimates that non-utility providers, including CCAs, will provide 85% of electricity generation by the mid-2020s. However, the utilities will likely continue to:

- » Operate the transmission and distribution (T&D) system financially supported by all ratepayers, including CCA customers
- » Provide data and appropriate incentives to the market to help support grid operations
- » Collaborate with first responders to lead emergency response efforts, an obligation for which the utilities collect funds from all ratepayers, including CCA customers.

The Evolving Role of the CPUC

Historically, the CPUC developed around regulating a monopoly, profit-driven utility industry. CCAs, however, make procurement decisions guided by statewide standards and considering local priorities and long-term stability. The state can rely on statewide standards and does not need a centralized procurement model to ensure state goals are achieved. MCE proposes that the CPUC focus its role in the transforming energy market on the following:

- » Continuing to set and enforce key standards
- » Informing customers about price details and energy choices
- » Safeguarding against anti-competitive practices
- » Cultivating innovation
- » Advancing social equity and environmental justice
- » Facilitating collaborative dialogue between regulators, stakeholders, and the legislature through an annual en banc on the State of the Electricity Market



DO YOU HAVE QUESTIONS?

Michael Callahan
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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)**

**PREPARED DIRECT TESTIMONY OF WITNESSES
LORENZO KRISTOV, RICHARD MCCANN AND SHEHZAD WADALAWALA
ON BEHALF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

TRACK II ISSUES

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July 10, 2018

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**APPENDIX A – Transition Program Process Overview and
Timeline**

WITNESS QUALIFICATIONS

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List of Acronyms

CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator or Community Choice Aggregation
CPM	Capacity Procurement Mechanism
DA	Direct Access
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distribution Resources Plan
EE	Energy Efficiency
ERR	Essential Reliability Resource
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
GAM	Green Allocation Mechanism
IDER	Integrated Distributed Energy Resources Proceeding
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan Proceeding
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LSE	Load Serving Entity
OTC	Once-Through Cooling
PCIA	Power Charge Indifference Adjustment
PPA	Power Purchase Agreement
PTO	Participating Transmission Owner
RA	Resource Adequacy
RFO	Request for Offer
RMR	Reliability Must Run
RPS	Renewables Portfolio Standard
UDC	Utility Distribution Company
UOG	Utility Owned Generation

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**PREPARED DIRECT TESTIMONY ON BEHALF OF THE
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

I. INTRODUCTION AND EXECUTIVE SUMMARY

California’s continued leadership in setting and achieving critical targets for reducing greenhouse gas emissions and moving to clean energy is of global importance. Leadership is also critical to the health and safety of all Californians – both present and future – a point highlighted by the already visible impacts of the changing climate. Local communities have embraced the state’s call for local action by forming community choice aggregators (CCAs) to build on state efforts. Continued success in achieving the state’s emissions reduction and clean energy targets depends on continuing the evolution of California’s regulatory programs and policies, including resource adequacy (RA) program rules and procurement structures.

The need to evolve the RA framework is driven primarily by three key changes. Fossil-fired and nuclear power plants that have long played a role in grid reliability are retiring, sometimes before alternative clean energy solutions can be implemented. In addition, the growth of diverse distributed energy resources (DER) is making it harder to forecast net demand, set Local RA requirements and to determine how those requirements will be met. Finally, the transition of the Commission-jurisdictional retail

1 market from a few large investor-owned utilities (IOUs) to an increasing number of
2 smaller load-serving entities (LSEs) increases the need for the Commission’s
3 coordination of LSEs’ efforts in meeting RA requirements.

4 The most recent annual RA compliance cycle for 2018 emphasized the
5 importance of the greater coordination in meeting Local Capacity Requirements (LCRs).
6 In the PG&E Transmission Access Charge (TAC) area, there was a 1,071.76 MW total
7 deficiency due to sub-area constraints while individual LSE deficiencies totaled 72.23
8 MW.¹ The shortfall required supplemental backstop procurement by the California
9 Independent System Operator (CAISO), leading to collective overprocurement of Local
10 RA and unnecessary costs for ratepayers.

11 The Commission responded to these challenges² in its Track 1 Decision, D.18-06-
12 030, directing stakeholders to propose multi-year Local RA programs and central buying
13 for at least some portion of Local RA. The Track I Decision, along with the Scoping
14 Memo and recent Customer Choice *en banc* hearing, highlight key objectives and issues
15 that must be addressed to respond effectively to the evolving RA landscape:

- 16 ✓ Ensuring sufficient resource availability to maintain required and expected
17 levels of system reliability;
- 18 ✓ Avoiding collective overprocurement of Local RA and mitigating unnecessary
19 ratepayer costs;
- 20
- 21

¹ CAISO Evaluation Report of Load Serving Entities’ Compliance with 2018 Local and System Resource Adequacy Requirements, November 13, 2017.

² The Commission also responded directly to the CAISO’s backstop procurement for 2018 through Resolution E-4909, issued on January 11, 2018, authorizing PG&E “to hold a competitive solicitation for energy storage and preferred resources to address two local sub-area capacity deficiencies and to manage voltage issues in another sub-area.” The Resolution contemplated that this procurement would result in “lower overall ratepayer costs.” Resolution E-4909 at 1.

- 1 ✓ Preserving LSE procurement preferences for local, clean resources to meet
2 RA requirements;
- 3
- 4 ✓ Allocating the cost of meeting LCRs equitably among LSEs;
- 5
- 6 ✓ Mitigating planned and unplanned resource retirement, which has resulted in
7 out-of-market backstop procurement by the CAISO;
- 8
- 9 ✓ Reducing market and regulatory uncertainty, which is leading to stagnation of
10 new preferred resource build-out to replace retiring resources;
- 11
- 12 ✓ Realigning scale between buyers and sellers (large existing assets and smaller
13 LSEs);
- 14
- 15 ✓ Increasing the transparency of market information to ensure efficient and
16 economic procurement of needed Local RA resources;
- 17
- 18 ✓ Mitigating market power (total and partial) in local capacity areas (LCAs)
- 19
- 20 ✓ Decarbonizing the electricity sector by addressing California’s goals to
21 eliminate gas-fired generation, reducing the impacts on Disadvantaged
22 Communities (DACs), and leveraging trends in DER growth.
- 23

24 Immediate progress on many of these issues can be made through near-term
25 implementation of a transitional multi-year Local RA program that will ensure local
26 reliability while mitigating impacts on ratepayers. A more comprehensive long-term
27 planning and deployment process is also needed, however, to reduce reliance on fossil-
28 fuel generation³ and address other broader policy goals.

29 Based on these considerations, CalCCA proposes a two-phase approach to
30 addressing local reliability needs. The multi-year-forward Transition Program would
31 begin in 2019 for compliance in 2020 and beyond. The Transition Program relies on a
32 rolling three-year forward Local RA procurement requirement for all LSEs, in

³ CalCCA understands that some existing fossil-fuel resources may still be needed for system flexibility even after they are no longer needed for local-area reliability. CalCCA anticipates that the long-term strategy proposed here can and will be targeted to obviate these needs as well by facilitating development of flexible preferred resources.

1 compliance with the Track I Decision, aimed to address the shortcomings identified with
2 the existing program. In parallel, the proposed Long-Term Strategy coordinates LSE
3 procurement (consistent with Integrated Resource Plan (IRP) and RA obligations) with
4 the CAISO transmission planning process (TPP) to deploy preferred resources to address
5 local constraints. Together, these actions will enable the Commission and stakeholders to
6 address all key issues and provide an orderly transition from our present capacity fleet to
7 a carbon-free capacity fleet, thereby ensuring grid reliability, minimizing ratepayer costs
8 and accelerating achievement of California’s climate goals.

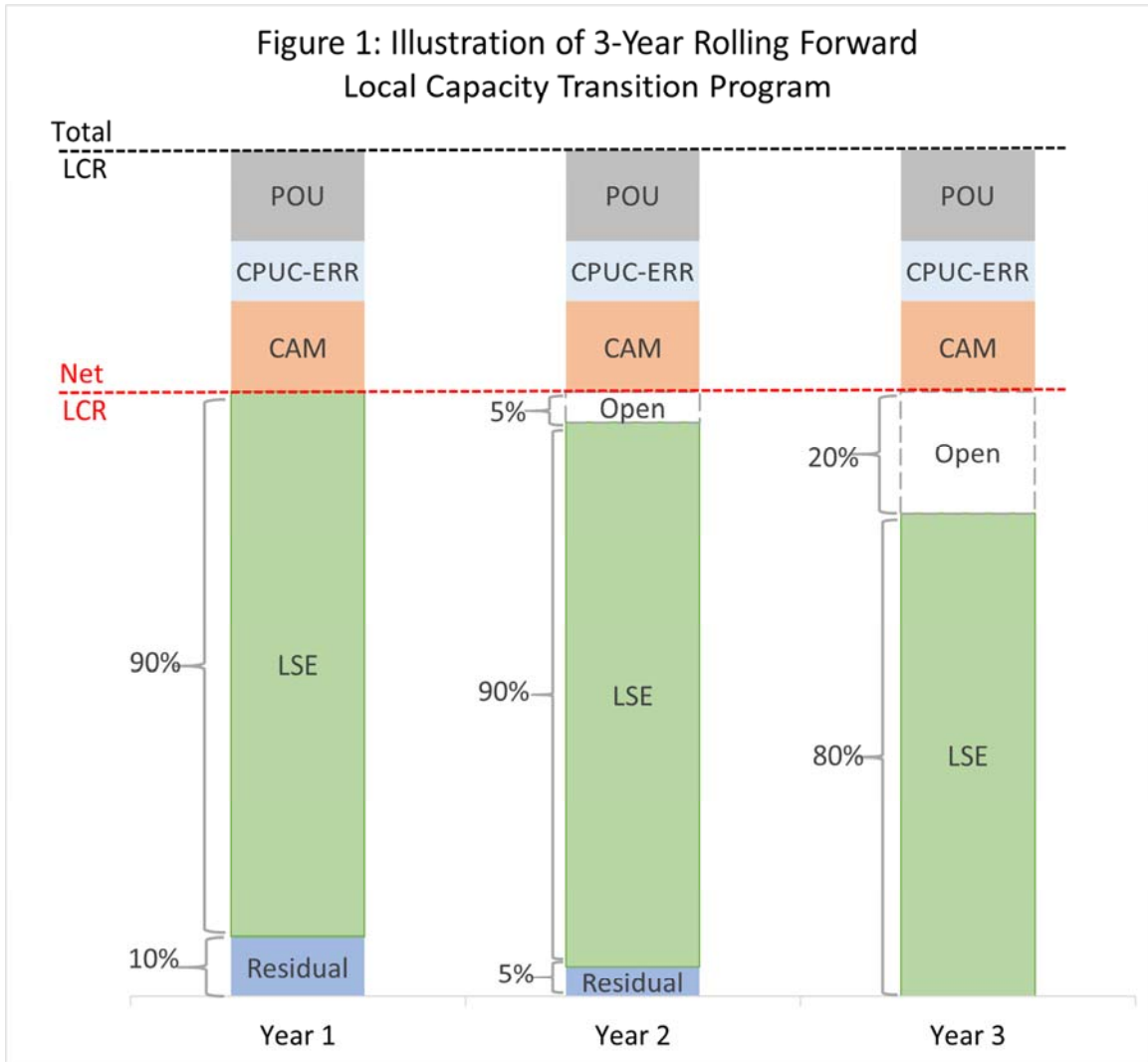
9 **A. Summary of CalCCA’s Proposed Transition Program**

10 CalCCA’s Transition Program envisions (i) a three-year Local RA procurement
11 obligation for LSEs, (ii) greater transparency of reliability needs in local sub-areas, and
12 (iii) a centrally procured residual Local RA amount in each LCA. Under the program,
13 greater sub-area transparency, along with the Commission’s coordination of LSE
14 procurement and central buying, ensures meeting 100 percent of Local RA requirement
15 for Year 1 and 95 percent and 80 percent for Years 2 and 3, respectively. These
16 objectives would be met through assignment to each LSE of its proportionate share of the
17 net local capacity requirement (Net LCR) for each LCA. Net LCR is the load-forecast-
18 based Total LCR from the CAISO LCR studies reduced by:

- 19 1) The proportionate share of the Total LCR to be procured by Publicly
20 Owned Utilities (POUs) within the LCA; and
21
22 2) The CPUC Jurisdictional LSEs’ share of expected procurement of
23 “Essential Reliability Resources” (ERR) – resources for which there are
24 no substitutable resources⁴ – identified by the CAISO as necessary to
25 address LCA or sub-area requirements; and

⁴ CalCCA proposes that any pivotal supplier in a sub-area, *i.e.* a resource some of whose capacity will be needed even if all other resources in the sub-area are procured for their full

1 3) The Commission’s allocation to LSEs of resources under the Cost
 2 Allocation Mechanism (CAM) and any other allocation of Local RA
 3 resources held in the IOUs’ portfolios.
 4
 5 LSEs in Years 1 and 2 of the three-year RA cycle must procure 90 percent of their shares
 6 of the Net LCR for each LCA with the remainder procured by a Central Buyer. For Year
 7 3 LSEs must procure 80 percent of their Net LCR shares.



8

capacity, is necessarily an ERR. Further, if a resource is determined to be pivotal supplier in Year 2 or Year 3 but not preceding years (most likely due to planned plant retirements in the sub-area), it should also be designated as an ERR in all preceding years to ensure it does not retire prematurely.

1 To ensure proper incentives for LSEs to invest in new carbon-free resources to meet their
2 requirements and relieve constraints, the LSE’s Year 2 and 3 obligations can be met with
3 newly contracted resources under certain conditions, as discussed in Section III.
4 Section III explains how LSE procurement and Central Buyer procurement together
5 achieve the Local RA needs on a rolling annual basis. It also describes all the steps of the
6 Transition Program. Appendix A provides a detailed time line.

7 CalCCA proposes that the Central Buyer bear ultimate responsibility to procure
8 the ERRs, with an opportunity in advance of this procurement for LSEs to meet or beat
9 the CAISO’s Capacity Procurement Mechanism (CPM) Soft Offer Cap (SOC). The
10 Central Buyer would also be responsible to procure the Residual Need, defined as 10% of
11 the Net LCR for Year 1 and 5% of the Net LCR for Year 2.

12 CalCCA recommends that the CAISO serve as Central Buyer for the ERRs and
13 the Residual Need, as defined in this testimony. By leveraging the existing procurement
14 mechanisms authorized to the CAISO by the Federal Energy Regulatory Commission
15 (FERC), specifically the CPM and Reliability Must Run (RMR), with certain refinements
16 explained later herein, the Transition Program is best positioned for success.

17 Designating the CAISO as residual Central Buyer:

- 18 • Minimizes wholesale market jurisdictional conflicts between the
19 Commission and FERC,⁵ preventing potentially more sweeping market
20 reform by FERC;
21

⁵ Examples of potential jurisdictional conflicts include FERC-directed capacity market design, as FERC’s rejection of the PJM ISO capacity market proposal (FERC, “Order Rejecting Proposed Tariff Revisions, Granting In Part And Denying In Part Complaint, And Instituting Proceeding Under Section 206 Of The Federal Power Act,” Docket Nos. EL16-49-000 et al, June 29, 2018), and Complaint of CXA La Paloma, LLC to FERC, submitted June 20, 2018, asking for creation of a central buying authority for the CAISO to resolve its issues.

- Leverages the CAISO’s existing tools, which would not be available to any other Central Buyer, to mitigate local market power of FERC-jurisdictional wholesale generators;
- Permits the use of the CAISO’s cost allocation tools to ensure that all LSEs – including POUs and other LSEs outside the scope of Commission authority – pay for needed LCA resources;
- Avoids exacerbating the growing mismatch between the IOUs’ supply portfolios and their bundled demand; and
- Avoids the need to create yet another complex regulatory structure within California’s electricity market.

Only the CAISO as Central Buyer can meet these objectives.

Two additional issues require consideration. First, as the Commission contemplated in the Scoping Memo, transparency into sub-area requirements will better enable all procuring parties to achieve program objectives.⁶ Three-year forward forecasts regarding ERR requirements and CAM resources are a critical foundation to transparency. Transparency of other information will also be important to enable LSEs to understand sub-area dynamics such as resource effectiveness and the performance requirements for potential substitute preferred resources. Second, the Transition Program must be coordinated with market sales of excess Local RA in the IOUs’ portfolios, such as those under consideration in R.17-06-026, to enable LSEs collectively to achieve cost-effective compliance.

B. Summary of CalCCA’s Proposed Long-Term Strategy

CalCCA’s Long-Term Strategy proposal, described in detail in Section III of this testimony, is designed to complement the Transition Program proposal by substantially reducing or eliminating LCA sub-area issues and Local RA needs. This will be achieved

⁶ Citation to relevant section

1 primarily through LSE procurement of local preferred resources, thus reducing the need
2 for substantial CAISO procurement of fossil-fuel ERRs. To achieve this desired end
3 state, CalCCA proposes that the Commission adopt its stated goal, and provide a
4 structure and incentives for all LSEs (including CCAs), the IOUs (as PTOs and
5 distribution utilities as well as LSEs), developers of clean energy resources and other
6 stakeholders to collaborate in developing cost-effective alternatives to transmission
7 solutions identified in the TPP for reducing local grid constraints.⁷

8 The TPP uses the CEC IEPR demand forecast as a crucial input. This allows a
9 full accounting for California’s evolving demand for electricity and how it will be
10 affected by the projected growth of load modifiers (including energy efficiency, electric
11 vehicle and rooftop solar adoption). The TPP planning assumptions also reflect
12 scheduled power plant retirements (*e.g.*, once-through-cooling plants and Diablo Canyon)
13 and scheduled in-service dates of approved transmission upgrades. Thus, the TPP would
14 be the process, as it is today, for describing local reliability needs in sufficient detail to
15 inform design of effective solutions, identifying transmission solutions to meet the needs,
16 and evaluating proposed alternatives to determine the preferred solution.

17 The Long-Term Strategy builds on two ongoing trends and processes. First, the
18 ongoing growth of DERs is already reducing the need for reliability transmission
19 upgrades, as evidenced by the recent cancellation or downsizing of transmission upgrades

⁷ The Oakland Clean Energy Initiative described in the CAISO 2017-18 Transmission Plan (pp 128-129) is a successful example of such a process.
http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

1 that were previously approved based on expected future reliability needs.⁸ The proposed
2 strategy would build on this growth by targeting additional preferred resource
3 procurement by LSEs to offset LCRs, coordinated with the IRP process. Second, in April
4 2018 the CAISO announced a transmission study plan for the current 2018-19 planning
5 cycle aimed to reduce or eliminate Local RA needs in certain LCAs with fossil resources.
6 The CalCCA proposal would strengthen the impact of this effort by fostering
7 opportunities for stakeholders to propose non-wires alternatives (NWA) or alternative
8 transmission solutions (ATS), focused first on alternatives to eliminate fossil-fuel
9 generation located in DACs.⁹

10 The Commission must play a coordinating role in the Long-Term Strategy to
11 ensure that IOUs' distribution resource plans (DRP) consider the full value of DERs,
12 including load management measures, and that the needed preferred resource
13 development is integrated across the DRP, IRP, IDER, the CEC IEPR and the CAISO's
14 transmission plan. It must also resolve critical policy issues needed to ensure fair and
15 accurate compensation to local resources.

16 The success of CalCCA's proposed Transition Program and Long-Term Strategy
17 depend on collaboration and coordination among all LSEs, the Commission, the CAISO,

⁸ "Efficiency, DERs saving \$2.6B in avoided transmission costs, CAISO says," *Utility Dive*, <https://www.utilitydive.com/news/efficiency-ders-saving-26b-in-avoided-transmission-costs-caiso-says/519935/>, March 26, 2018. See CAISO 2017-18 Transmission Plan, pp 2-3.

⁹ An NWA is an electrical asset or set of assets that substitute for a transmission solution but are not themselves considered transmission assets. They are typically resources procured for energy and RA capacity by an LSE, and may be interconnected at either distribution or transmission level. A related but distinct concept is an ATS, which is an electrical asset or set of assets that substitute for a transmission solution and are compensated as transmission assets, owned by a PTO and operated as part of the CAISO controlled grid. The attractiveness of the ATS is its ability to earn all or part of its cost recovery as a rate-base grid asset. A solution to meet local reliability needs without a transmission upgrade could involve an NWA or an ATS or a combination of the two, but currently only the NWA construct is open to DERs.

1 the Energy Commission and the participating transmission owners. The Commission is
2 in a pivotal position to ensure this success through its administration of the Transition
3 Program and coordination of the Long-Term Strategy through the IRP, IDER, DRP and
4 other planning processes.

5 **II. THE EVOLVING CHALLENGES OF ENSURING LOCAL AREA**
6 **RELIABILITY**

7 Conditions for ensuring local grid reliability are changing, and changes are
8 required in the mechanisms used to meet this objective. The key drivers of these changes
9 include (1) the growth in DER resources, (2) the increasing number of LSEs in the
10 market and (3) the impending retirement of fossil-fuel resources. Even without these new
11 challenges, Local RA procurement has occurred under challenging conditions: (1) the
12 complexity of local grid topology and operations, which creates locationally granular
13 resource needs, and (2) local market power on the part of certain resources within the
14 local areas for which there are no current alternatives (*i.e.*, no competition).¹⁰ Under
15 these conditions, some backstop procurement may be needed even when all LSEs fully
16 meet their Local RA procurement requirements – a problem that arose for the 2018 RA
17 compliance year. Any proposed Local RA solution must thus directly address these
18 conditions.

¹⁰ Because the transmission constraints that drive local capacity needs pre-date the formation of wholesale power markets in California, the market power of essential local resources has been an issue since the start-up of the CAISO in 1998. The reliability must-run (RMR) mechanism has been the FERC-approved means to procure such resources at mitigated cost-of-service prices since the beginning of California's electricity market reform.

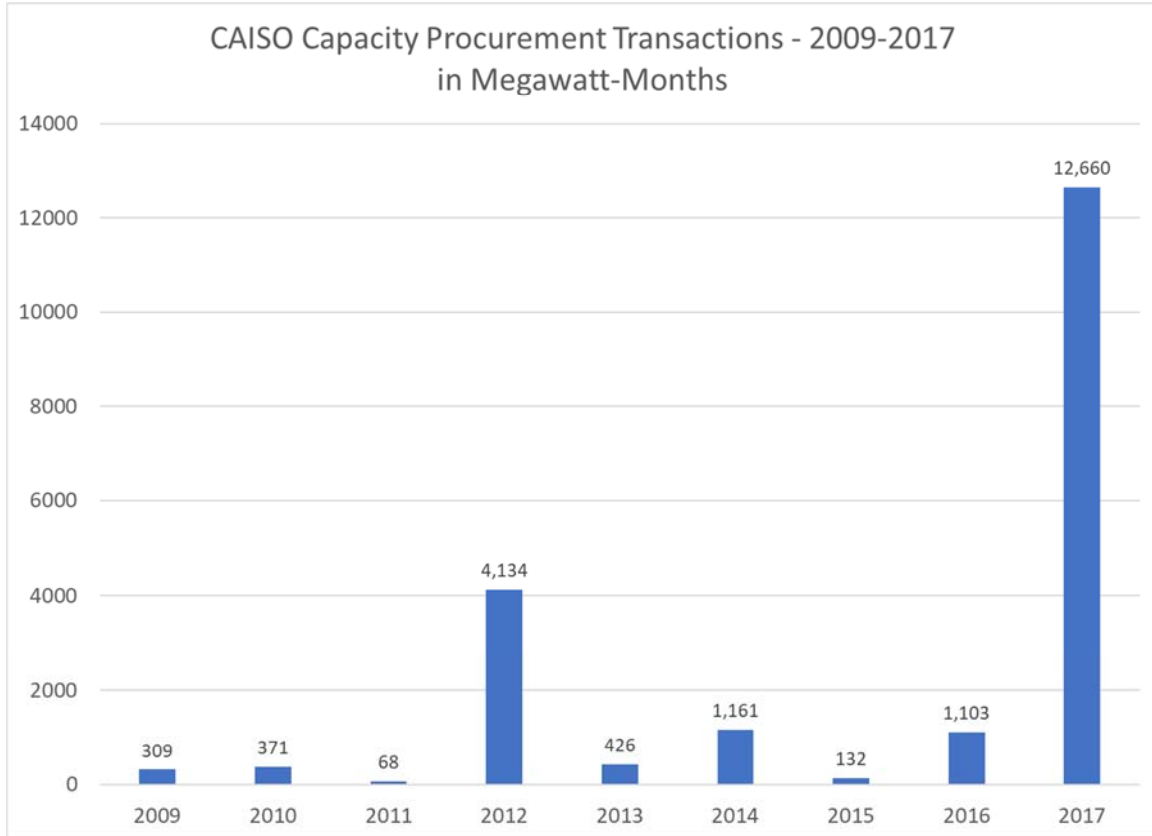
1 **A. Changing Market Dynamics**

2 In the context of Resource Adequacy, a Local Capacity Area (LCA) is a portion
3 of the CAISO-controlled transmission grid characterized by a need for supply resources
4 located within the area to meet the demand within the area. The need for local supply
5 resources arises due to one or more transmission grid constraints into or within the LCA
6 that prevent the area from fully relying on importing power from elsewhere in the grid to
7 meet demand. These conditions are most prevalent where there are high levels of in-area
8 demand and when contingency events take some grid facilities out of service. Thus, in
9 principle, needs for local-area resources could be eliminated by upgrading the
10 transmission grid in those areas. Until recently, however, existing local resources have
11 met the needs and local transmission upgrades have not been deemed to be needed or
12 cost-effective. The Local RA requirements have ensured that LSEs procure the needed
13 local resources, on an annual basis prior to each compliance year, at reasonable cost
14 under most circumstances, with rare need for backstop procurement by the CAISO.

15 Figure CCA-2, below, illustrates the amount of CPM capacity procured by the
16 CAISO from 2009 to 2017. Even with the substantial increase in 2017 (largely due to
17 issuing one-year agreements instead of one to two months which had been standard
18 previously), this amounts to about 1,050 MW on average each month compared to a
19 system wide peak of 50,116 MW.

1

Figure CCA-2



2

3

Going forward, any local reliability mechanism must meet the challenges

4

presented by fossil resource retirement, DER growth and the increasing number of LSEs

5

serving the retail market. Existing fossil-fuel generators have traditionally met a major

6

share of the local-area needs. The desire to rely on these resources, however, is declining

7

due to the state's focus on decarbonization and the elimination of once-through cooling

8

(OTC) generation. While transitioning towards a carbon free fleet, economic trends

9

challenge the financial viability of resources that are needed in the interim. In addition to

10

power plant retirement, DER growth complicates planning any local reliability solution.

11

While DER development initially accelerated through deployment of rooftop solar

12

photovoltaic (PV) resources, DER potential is more diverse due to the success of

13

California's programs promoting storage, electric vehicle charging, dispatchable demand

1 and more. These resources add complexity in demand forecasting and quantifying LCR.
2 DER also presents jurisdictional issues – with the local area transmission constraint
3 arising under one jurisdiction (FERC) and potential DER solutions under another
4 (CPUC). Finally, the complications presented by plant retirement and DERs are
5 heightened by the growing number of CCAs.¹¹ While CCAs present the potential for
6 more effective identification and deployment of local solutions, their growth also
7 highlights the need for area-wide coordination in Local RA procurement to ensure
8 collective procurement sufficiency.

9 **B. Local Sub-Area Market Power**

10 Local market power arises when an ERR holds market power in an LCA or sub-
11 area because there is no other combination of resources that can meet the local reliability
12 need. Competitive procurement is not a near-term option; given the lack of competitive
13 alternatives, only new resources can effectively mitigate market power, and these
14 resources take time to deploy.¹² Even where there is only partial market power, resources
15 can command a higher price than other Local RA resources knowing that they will likely
16 be procured through the CAISO’s Capacity Procurement Mechanism at or near the Soft
17 Offer Cap. Consequently, an individual LSE may be reluctant to procure the essential
18 resource because to do so would subsidize other LSEs who meet their shares of the LCR
19 with less costly, non-essential resources. For this reason, and due to a lack of

¹¹ The Direct Access ESPs are also LSEs with Local RA requirements, but because their share of system demand has been limited by statute and has remained relatively stable in recent years they have been less of a factor in the recent changes to the Local RA landscape.

¹² And prior to the development of distributed energy resources, physical constraints on building new utility-scale generation or sufficiently large transmission interconnections were often an effective barrier to increasing competition. In addition, the pecuniary impact from market entry that would tend to drive down the price in the local area so that the new entrant may not gain sufficient economic rents to recover its investment.

1 transparency, these resources may not be procured by LSEs. These factors thus motivate
2 the role of the Central Buyer, as the CAISO has had to step in for the 2018 RA year to
3 procure these essential sub-area resources needed to ensure local reliability.

4 Not surprisingly, the higher value of these resources due to their position in the
5 market has resulted in them receiving higher prices. The CAISO has paid prices through
6 the Capacity Procurement Mechanism (CPM) and Reliability Must Run (RMR) contracts
7 that are higher than the short-term prices reported by the Commission’s Energy Division
8 for other Local RA.¹³

9 **C. CAISO RMR and CPM Procurement**

10
11 An understanding of the circumstances under which CAISO RMR or CPM¹⁴
12 backstop has been required will help create reasonable expectations for a multi-year
13 program and central buyer structure.

14 Two circumstances in which the CAISO engages in backstop procurement
15 through the CPM are particularly relevant in this proceeding. The CAISO procures Local
16 RA resources through this mechanism to address (1) deficiencies in collective LSE Local
17 RA procurement, including deficiencies that may arise due to sub-area constraints despite
18 compliance by all LSEs, and (2) “capacity at risk of retirement within the RA
19 Compliance Year that will be needed for reliability by the end of the calendar year
20 following the current RA Compliance Year.”¹⁵ In some cases, these resources may have
21 partial market power as pivotal suppliers or by virtue of their higher effectiveness at
22 meeting granular local reliability needs than other potentially substitutable resources.

¹³ CPUC, *The 2016 Resource Adequacy Report*, Energy Division, June 2017.

¹⁴ 2018 was the first year that the CAISO used its CPM authority in the year-ahead timeframe to address a collective deficiency for any IOU service territory.

¹⁵ *Id.* §43A.2.

1 While these resources may face some degree of competition in their sub-area, in both
2 cases the value of the resource is likely to be relatively high.

3 As part of the RA process, the CAISO engages in backstop procurement only
4 after issuing a Market Notice identifying the needed resource and providing LSEs the
5 opportunity to procure the resource. If no LSE cures the deficiency, the CAISO procures
6 the needed resources, typically at the Soft Offer Cap (currently \$6.31/kW-month).^{16,17} If
7 the specific generator whose capacity is needed is unwilling to contract at or below the
8 Soft Offer Cap, the parties may seek authority for an RMR-like COS rate from FERC.¹⁸

9 Under the CPM, cost recovery includes the generator's variable costs, net of
10 market revenues, and some amount of capital maintenance expense to ensure cost
11 coverage and some degree of profit. The CPM is based on the going forward costs for an
12 ongoing operation but does not consider recovery of capitalized maintenance costs.

13 When possible, the CAISO procures Local RA capacity voluntarily through its
14 Competitive Solicitation Procedure (CSP) under its Tariff Section 43.A. A review of
15 CPM transactions for 2009 to 2017, shown in Table CalCCA-1, reveals all but a handful
16 of transactions were priced at the SOC.

¹⁶ *Id.* §43A.4.1.1.

¹⁷ The initial soft cap was set in 2009 based on the going forward fixed costs for a combustion turbine estimated from siting case submittals in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, CEC-200-2007-011-SF, December 2007. The cap was revised updated for the survey results from 20 combined cycle plants reported in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, CEC-200-2009-07-SF, January 2010. (Dr. McCann was the lead consultant author on both reports.) The soft cap has been revised several times subsequently as described in CPUC, *The 2016 Resource Adequacy Report*, Energy Division, June 2017, p. 32.

¹⁸ CAISO Fifth Replacement Electric Tariff, §43A.4.1.1.1.

Table CCA-1

CAISO CPM Transactions - 2009-2017						
Year	Resource	CPM designation (MW)	CPM designation dates (Mo./Day)	Price \$/kW-Mo.	Estimated cost	Local capacity area
2009	Yuba City Energy Center 1	1	4/21 - 5/20	\$3.42	\$3,417	Sierra
2009	Humbolt Mobile #2 2	15	6/20 - 6/30	\$4.28	\$21,403	Humbolt
2009	Moutainview #3	2	8/2 - 8/31	\$1.95	\$3,892	LA Basin
2009	Moutainview #4	2	8/2 - 8/31	\$1.95	\$3,892	LA Basin
2009	Humbolt Mobile #2	15	8/7 - 9/7	\$1.43	\$21,403	Humbolt
2009	Balch #3	1.5	8/20 - 9/18	\$3.89	\$5,837	Fresno
2009	Creed Energy Center #1	48	10/13 - 11/11	\$3.89	\$186,796	Bay Area
2009	Feather River Energy Center #1	1	10/13 - 11/11	\$3.89	\$3,892	Sierra
2009	Gilroy Energy Center #3	46	10/13 - 11/11	\$3.89	\$179,013	Bay Area
2009	Goose Haven Energy Center #1	48	10/13 - 11/11	\$3.89	\$186,796	Bay Area
2009	King City Energy Center #1	44.6	10/13 - 11/11	\$3.89	\$173,565	
2009	Lambie Energy Center #1	48	10/13 - 11/11	\$3.89	\$186,796	Bay Area
2009	Wolfskill Energy Center #1	46	10/13 - 11/11	\$3.89	\$179,013	Sierra
2010	El Segundo #4 1	20	1/5 - 2/3	\$3.89	\$77,832	LA Basin
2010	Delta Energy Center 2	127	4/30 - 5/29	\$3.89	\$494,192	Bay Area
2010	Yuba City Energy Center 3	1	7/18 - 8/16	\$3.89	\$3,892	Sierra
2010	Huntington Beach #3 and #4 2	182	8/17 - 9/22	\$3.89	\$708,268	LA Basin
2010	Mindalay #1 and #2 4	40	9/27 - 10/26	\$3.89	\$155,664	BC - Ventura
2010	CalPeak - Enterprise and Border 1	0.7	10/12 - 11/10	\$3.89	\$2,723	San Diego
2011	Moss Landing Power Block 21	75	9/9 - 9/30	\$5.26	\$354,988	
2011	Moss Landing Power Block 21	45	10/1 - 10/7			

CAISO CPM Transactions - 2009-2017						
Year	Resource	CPM designation (MW)	CPM designation dates (Mo./Day)	Price \$/kW-Mo.	Estimated cost	Local capacity area
2012	Huntington Beach Unit 1	20	2/8 - 3/8	\$6.09	\$121,810	LA Basin
2012	Huntington Beach Unit 1	98	3/1 - 4/29	\$6.41	\$1,255,748	LA Basin
2012	Encina Unit 4	300	3/1 - 4/29	\$6.41	\$3,844,125	San Diego
2012	Huntington Beach Unit 1	226	5/1 - 6/29	\$6.40	\$2,892,704	LA Basin
2012	Huntington Beach Unit 3	225	5/11 - 10/31	\$6.19	\$8,360,972	LA Basin
2012	Huntington Beach Unit 4	215	5/11 - 10/31	\$6.19	\$7,989,373	LA Basin
2012	Huntington Beach Unit 1	226	9/5 - 10/4	\$6.40	\$1,446,352	LA Basin
2013	Morro Bay Unit 4	50	2/22 - 4/22	\$6.41	\$640,815	CAISO System
2013	Huntington Beach Unit 2	163	9/1 - 10/30	\$6.41	\$2,088,642	LA Basin
2014	High Desert Power Project Aggregate	181	2/6 - 3/7	\$6.41	\$1,159,644	CAISO System
2014	Moss Landing 2	490	10/2 - 12/1	\$6.73	\$6,593,139	CAISO System
2015	Moss Landing 6	52	6/30 - 7/29	\$0.22	\$11,661	CAISO System
2015	Oildale 1	40	7/15 - 9/12	\$6.73	\$538,215	CAISO System
2016	MANDALAY GEN STA. UNIT 2	20.01	11/8 - 1/6	\$6.31	\$252,526	SCE TAC
2016	MANDALAY GEN STA. UNIT 3	130	11/9 -12/9	\$6.31	\$820,300	System
2016	Pio Pico Unit 1	102.67	11/9 -12/9	\$6.31	\$647,848	System
2016	Pio Pico Unit 2	102.67	11/9 -12/9	\$6.31	\$647,848	System
2016	Pio Pico Unit 3	102.67	11/9 -12/9	\$6.31	\$647,848	System
2016	Sentinel Unit 1	1	11/9 -12/9	\$6.31	\$6,310	System
2016	Sentinel Unit 2	1	11/9 -12/9	\$6.31	\$6,310	System
2016	Sentinel Unit 3	1	11/9 -12/9	\$6.31	\$6,310	System
2016	Sentinel Unit 6	1	11/9 -12/9	\$6.31	\$6,310	System
2016	DELTA ENERGY CENTER AGGREGATE	114	12/14 - 2/11	\$6.31	\$1,438,680	PG&E TAC

CAISO CPM Transactions - 2009-2017						
Year	Resource	CPM designation (MW)	CPM designation dates (Mo./Day)	Price \$/kW-Mo.	Estimated cost	Local capacity area
2016	Los Medanos Energy Center AGGREGATE	89.79	12/14 - 2/11	\$6.31	\$1,133,150	PG&E TAC
2016	MOSS LANDING POWER BLOCK 1	141.04	12/18 - 1/17	\$6.31	\$1,779,925	System
2016	Mountainview Gen Sta. Unit 3	36.37	12/19 - 2/16	\$1.90	\$138,206	SCE TAC
2017	MOSS LANDING POWER BLOCK 1	510	Annual	\$6.19	\$37,882,800	PG&E
2017	ENCINA UNIT 4	272	Annual	\$6.31	\$20,595,840	SDG&E
2017	ENCINA UNIT 5	273	Annual	\$6.31	\$20,671,560	SDG&E

1 Unlike the CPM, RMR contracts have been part of the CAISO grid management
2 tools since the initiation of the restructured market in March 1998. RMR resources are
3 defined as:

4 Generation that the ISO determines is required to be on line to meet
5 Applicable Reliability Criteria requirements. This includes: i) Generation
6 constrained on line to meet NERC and WECC reliability criteria for
7 interconnected systems operation; ii) Generation needed to meet Load
8 demand in constrained areas; and iii) Generation needed to be operated to
9 provide voltage or security support of the ISO or a local area.¹⁹

10 As described in the Commission’s 2016 Resource Adequacy Report, RMR contracts are
11 annual agreements that are reviewed and renewed as needed. RMR contracts typically
12 have been provided to resources for which there are no substitute resources. The contracts
13 typically have a one-year term that can be renewed annually under the same terms and
14 conditions, with compensation set at a price based on the generator’s cost-of-service
15 (COS). COS prices are necessary because these resources are local monopoly resources
16 and thus could charge exorbitant rates if procured at “market-based” prices.

17 In their most recent incarnation, RMR contracts are offered to units that did not
18 bid or accept a voluntary CPM offer, but are still needed for local reliability and stability
19 purposes. Units designated as RMR may receive cost-based remuneration above the CPM
20 SOC with approval of the FERC. However, these prices are not completely comparable
21 “apples to apples” with CPM because CPM recipients retain all wholesale market
22 revenues while for these RMR Condition 2 contracts (which are must-offer bidders), the
23 wholesale revenues are to be returned to the CAISO, hence the “potential” cost

¹⁹ CAISO Fifth Replacement Electric Tariff, March 16, 2018, Appendix A Master Definition Supplement.

1 description. Table CalCCA-2 lists the most recent additions to the RMR designations for
2 2018, and the contracted price in \$/kW-month.

3 **Table CalCCA-2**

RMR Unit Designation for 2018	NQC MW (Aug.)	Potential Cost (\$/kW-Month)
Metcalf	580	\$10.41
Yuba City	47.6	\$7.81
Feather River	47.6	\$7.76

4

5 The higher value of these critical resources is also confirmed by the prices paid by
6 the IOUs for utility-owned generation (UOG) providing Local RA in their service
7 territories. Southern California Edison (SCE) paid \$435,219,778 in 2017 for 2,534.3 MW
8 of CAM reliability capacity at an average price of \$14.31/kW-month according to SCE's
9 2017 FERC Form 1 filing. Pacific Gas and Electric Company's (PG&E's) FERC Form 1
10 reveals a cost of \$203,474,897 for 1,637.3 MW of CAM resources, at an average price of
11 \$10.36/kW-month. For PG&E's PCIA-eligible fossil RA generation PPAs, the total cost
12 was \$478,244,526 for 2,486.4 MW at an average cost of \$16.03/kW-month.

13 The key lesson from these observations is that expecting resources with partial or
14 complete market power to negotiate "competitive" rates that resemble the short-term
15 price for Local RA is unrealistic. These resources, as rational market actors, will
16 logically seek to recover as much as they can from buyers, whether the CAISO, IOUs,
17 other LSEs or a new Central Buyer. Until local sub-area constraints are eliminated, these
18 resources can demand higher prices and their market power is only limited by the CAISO
19 authority to require acceptance of an RMR contract that is tied to their cost of service.
20 Only the imposition of a FERC-authorized mechanism can limit those prices to either a
21 defined cost basis under a voluntary transaction or an approved cost of service basis for

1 must-offer resources. A Central Buyer will need this same authority to compel generator
2 participation. Nevertheless, a Central Buyer is only needed to procure from these pivotal
3 suppliers for the period when those resources can exert market power. With the
4 successful implementation of the Long-Term Strategy, that role should diminish as local
5 sub-area constraints continue to be removed.²⁰ Once market power is addressed, LCRs
6 can be defined at sufficient granularity to align with the CAISO's actual grid needs,²¹

7 CalCCA does not dismiss the possibility of achieving prices below the Soft Offer
8 Cap for these resources with more transparent information and an expanded procurement
9 timeline. In the near term, the most viable way of achieving lower prices— as the
10 Commission has fully recognized – is to offer the generator multi-year contracts.

11 **III. CALCCA'S PROPOSED TRANSITION PROGRAM**

12 The economic interests of all LSEs are naturally aligned to ensure local area
13 reliability while reducing overprocurement of Local RA and ratepayer costs. Pending
14 physical solutions to address underlying local area constraints, and consistent with the
15 Commission's directives, CalCCA's Transition Program will achieve these objectives
16 through (1) a three-year compliance obligation, (2) greater transparency in local sub-
17 areas, and (3) a centrally-procured residual Local RA amount in each local capacity area
18 (LCA). Added transparency into local area and sub-area requirements will also

²⁰ For example, when the restructured market was initiated in March 1998, the vast majority of power plants in the Los Angeles Basin had at least one unit on a RMR agreement. Today, almost all of those plants have been removed from the RMR designation contracts and a few show up on the CPM procurement list.

²¹ In the development of the LCR framework, the Commission chose to aggregate six of the local capacity areas in PG&E's TAC area, to mitigate local market power concerns (See Energy Division Proposal, p. 12.)

1 incentivize and maximize opportunities for LSEs, separately or collectively, to procure
2 effective Local RA capacity and reduce the need for central buying.

3 Recognizing that some degree of central buying may be necessary in the near
4 term – particularly for resources with market power – CalCCA proposes to rely on the
5 CAISO as the Central Buyer for the residual Local RA needs, using existing mechanisms
6 modified as described below to meet current needs. The CAISO appears to be the ideal
7 entity, with the tools and legal authority to spread costs across both IOU and POU service
8 territories based on cost-of-service rates (if and when negotiation with the essential
9 resources fail) until local constraints can be relieved. The CAISO is also well positioned
10 to compensate LSEs who step forward to procure sub-area resources to the benefit of all
11 LSEs with modifications to the existing CPM cost allocation.

12 **A. Transition Program Mechanics**

13 CalCCA has identified six key steps in a rolling, annual, three-year-forward RA
14 program. The six steps would occur over a 15-month period leading up to the start of
15 each three-year RA compliance cycle. In conjunction with the proposed six-step
16 structure, CalCCA recommends the RA compliance year be re-defined on an April 1 to
17 March 31 basis rather than the calendar year, as discussed further below. Thus, the
18 timeline for the six steps would occur from January 1, 2019 through March 31, 2020 for
19 the April 2020-March 2023 RA cycle.

20 The six steps, with illustrative timings for each of them, are as follows:

21 Step 1: CAISO performs LCR studies to determine Total LCR values for each
22 year of the upcoming three-year RA cycle and for each LCA, and
23 identifies Essential Reliability Resources (ERR), if any (January 1 –
24 May 31, 2019)
25

- 1 Step 2: Utilities provide CAM forecasts to the CPUC for each year of the
2 upcoming RA cycle (by May 31, 2019)
3
- 4 Step 3: CPUC calculates annual Net LCR = (Total LCR – POU share – CPUC
5 Jurisdictional LSE share of ERR– CAM) for each LCA and allocates
6 shares to LSEs (by June 30, 2019)
7
- 8 Step 4: LSEs procure required percentages of their shares of Net LCR for each
9 of the three years, as specified in the table below (July 1 – September
10 30, 2019), a process that must be coordinated with any IOU sales of RA
11 to other market participants.
12
- 13 Step 5: LSE provide showings of their System, Flexible and Local RA
14 procurement for April 2020 through March 2023 to CPUC and CAISO
15 (by October 1, 2019)
16
- 17 Step 6: For each LCA CAISO calculates Residual needs, including needs driven
18 by sub-LCA constraints. The Central Buyer then procures the Residual
19 Need and any ERR capacity not already procured by LSEs (by
20 December 1, 2019 – four months ahead of the start of the next RA
21 compliance year).

22 Each step is discussed in detail below, and Appendix A provides a process overview and
23 timeline.

24 CalCCA’s six-step Transition Program does not depend on the proposed change
25 in the compliance-year time period from January 1 through December 31 to April 1
26 through March 31, and could be implemented without the change. A change in the
27 compliance period may be desirable, however, as certain existing processes would need
28 to be moved forward to preserve the four-month lead time between Step 6 and the
29 beginning of the compliance period.²² First, the change allows for greater certainty in
30 the results of the CAISO multi-year forecasts (Step 1). The CEC’s Integrated Energy

²² CalCCA proposes this four-month period based on the understanding that generating resources that may need to be procured by the Central Buyer need this much advance notice of procurement.

1 Policy Report (IEPR) demand forecast is critical to the CAISO’s study process. The CEC
2 typically adopts the forecast in January, suggesting that the CAISO cannot begin the
3 study process before February 1. Second, the change in timeline will allow the LSEs and
4 Central Buyer to complete all procurement, including contracts with ERRs that have local
5 market power, at least four months prior to the start of the compliance period (Step 6).
6 This schedule gives more certainty to generators which CalCCA expects will lead to
7 better maintenance planning, increased reliability and lower costs for ratepayers.

8 **STEP 1: CAISO Performs LCR Studies and Identifies Essential Reliability**
9 **Resources**

10
11 The Commission observed in the Scoping Memo²³ and D.18-06-30²⁴ that greater
12 transparency of resource requirements in local areas and sub-areas may be one means of
13 reducing out-of-market Local RA procurement. Step 1 of CalCCA’s Transition Program
14 thus starts with the CAISO LCR study process and concludes by May 31, when the
15 CAISO provides the LCR and identifies ERRs for each local area and each year of the
16 multi-year compliance period. In addition to ERRs, the CAISO LCR report identifies
17 available resources within an LCA and indicates their different effectiveness on critical
18 sub-area constraints. While this information will be useful to the CAISO as Central
19 Buyer, it will also be useful to LSEs as they conduct their Local RA procurement and
20 attempt to reduce the need for central buying. Lastly, the CAISO will identify what share
21 of the LCR in each LCA will be met by POU procurement.

²³ Scoping Memo at 4.

²⁴ D.18-06-030 at 44.

1 **STEP 2: Utilities Provide Multi-Year CAM Forecasts**

2
3 The allocation of Local RA capacity by the IOUs requires a clear understanding
4 of anticipated allocation of Local RA capacity by the IOUs under the Cost Allocation
5 Mechanism (CAM). Today, CAM allocations are provided by the CPUC in late July and
6 then trued up on a quarter-ahead basis during the compliance period. To support a multi-
7 year program, the IOUs must provide to the Commission their then-current three-year
8 forecasts of CAM resources for each LCA at the same time the CAISO provides its LCR
9 study results at the end of Step 1. The CPUC will use the CAM forecasts in Step 3 to
10 determine Net LCR amounts and allocate them to LSEs.²⁵ LSE specific CAM allocations
11 for Year 2 and Year 3 would be revised annually based on updated information and the
12 Year 1 allocations would be revised quarterly as is done today.

13 In addition to CAM Local RA resources, the IOUs currently hold Local RA
14 resources in their Power Charge Indifference Adjustment (PCIA) eligible portfolios.
15 While future disposition of these resources is under consideration in R.17-06-026,²⁶ the
16 CPUC must at a minimum receive this information from the IOUs by LCA and year and
17 include it in calculating the Net LCR allocations in Step 3.

18 **STEP 3: CPUC Allocation of Net LCR Requirements to LSEs**

19
20 Using the information from Steps 1 and 2 above and the CPUC Jurisdictional LSE
21 share of the Total LCRs, the Commission calculates Net LCR for each LCA and

²⁵ For the CPUC to allocate the Net LCRs for the three-year period to LSEs, it will need a three-year forecast from each LSE; CalCCA recommends that the current annual load forecast that is submitted in April be a three-year load forecast

²⁶ Proposals for disposition of this Local RA capacity include long-term resource or product sales (CalCCA) and quarterly allocation of Local RA attributes associated with hydro resources among LSEs (Joint Utilities) and periodic sales of Local RA attributes from other IOU resources (Joint Utilities).

1 compliance year. The Net LCR is calculated as (CPUC Jurisdictional LSE Share of Total
2 LCR – CPUC Share of ERR - CAM). The Commission then allocates shares of Net LCR
3 among jurisdictional LSEs. The CalCCA timetable calls for the Commission’s provision
4 of Net LCR allocations to LSEs by July 1.

5 **STEP 4: LSE Procurement of Net LCR**

6 Once the Commission has provided the Net LCR allocations, the LSEs have three
7 months (July – September) to secure 90 percent of their Net LCR shares for Years 1 and
8 2, and 80 percent for Year 3. LSEs would also have opportunities to procure prior to the
9 July 1 allocation but would have less information to rely upon before further Local RA
10 procurement. Setting LSE procurement requirements below 100 percent of the Net LCR
11 still results in procuring the required 100 percent of Net LCR for Year 1 and 95 percent
12 for Year 2 when combined with the Central Buyer procurement.²⁷ At the same time, these
13 LSE procurement levels provide headroom that the Central Buyer can use to address
14 remaining sub-area needs with reduced risk of over-procurement by the end of Step 6.
15 Table CCA-3 below shows CalCCA’s proposal for the LSE and Central Buyer
16 procurement shares of the Net LCR for each compliance year, and illustrating the rolling
17 three-year RA compliance cycle.

²⁷ The Central Buyer will not procure an ERR for Year 2/3 unless it is still not procured when it is needed for Year 1; this is necessary to avoid undermining ERR incentives to sign multi-year contracts with LSEs

Table CCA-3: Procurement of Net LCR by LSEs and Central Buyer

	2020-1	2021-2	2022-3	2023-4	2024-5
2020-22 RA Cycle	Year 1	Year 2	Year 3		
Net LCR achieved	100%	95%	80%		
LSE procurement requirement	90%	90%	80%		
Central Buyer procurement	10%	5%	0		
2021-23 RA Cycle		Year 1	Year 2	Year 3	
	Net LCR	100%	95%	80%	
	LSEs procure	90% (done already)	90% (10% more)	80%	
	Central Buyer	10% (5% more)	5%	0	
2022-24 RA Cycle			Year 1	Year 2	Year 3
		Net LCR	100%	95%	80%
		LSEs procure	90% (done already)	90% (10% more)	80%
		Central Buyer	10% (5% more)	5%	0

1 The LSE procurement efforts should focus not only on Local RA generally, but on ERRs
2 and other resources that are most effective in addressing sub-area constraints.

3 An LSE’s obligation may be met by new non-fossil resources. These resources
4 can be counted for Year 1 under existing guidance. Under the Transition Program, for
5 Years 2 and 3, these resources can be counted towards an LSEs requirement under three
6 conditions: (1) the LSE has executed a contract for purchase or development; (2) the
7 project is already in the utility’s or the CAISO’s interconnection queue and (3) the
8 scheduled commercial operation date falls on or before the first date of the compliance
9 month in which the LSE wishes to count the resources towards its obligation.

1 One additional factor must be considered. Several parties contemplated in R.17-
2 06-026 that the IOUs will sell some portion of their existing RA resources or, at a
3 minimum, RA products. It is critical that any IOU sales with Local RA value be timed
4 in a way that optimizes the potential for use by other LSEs and maximizes revenues for
5 ratepayers.

6 **STEP 5: LRA Compliance Showing**

7 LSEs would make their annual three-year showings on October 1. For Year 1,
8 this would also include the annual System and Flexible RA Showing. To the extent an
9 LSE falls short of its required Net LCR procurement share, that shortfall will be included
10 in the Central Buyer procurement in Step 6 with a corresponding adjustment to the LSE's
11 share of the Central Buyer's procurement costs. This is consistent with how the CAISO
12 handles individual LSE deficiencies in local capacity procurement today.

13 To the extent an LSE has met its Net LCR compliance target and has procured
14 excess Local RA in an LCA, no compensation would be provided to the LSE (e.g., in the
15 form of a reduced share of the Central Buyer procurement costs). This is consistent with
16 the practice today when an LSE showing includes Local RA in excess of its obligation
17 but the CAISO determines there is a collective deficiency. The reasoning is that self-
18 provision of Local RA beyond the Net LCR target does not necessarily offset needs for
19 the Central Buyer to procure highly-effective local resources on sub-LCA constraints. In
20 contrast, to the extent an LSE has procured ERRs, the procurement would offset its share
21 of the ERR costs 1:1 up to its proportional share of those costs because it would directly
22 offset the need for Central Buyer procurement. Further, the CAISO could also credit the
23 LSE for any excess ERRs procured beyond the LSE's load-ratio share at the CPM Soft

1 Offer Cap.²⁸ The credited costs will be recovered by the CAISO from all other LSEs,
2 including IOUs, POUs, CCAs and ESPs, in proportion to their unmet shares of these
3 critical resources. This outcome fairly allocates these costs to all entities that benefit and
4 incentivizes LSEs to procure from ERRs if they can obtain a price better than the CPM
5 Soft Offer Cap.

6 **STEP 6: CAISO Calculation of Residual Need and Central Buying**

7 Based on the October 1 LSE showings, the CAISO will assess residual or unmet
8 Local RA needs for each LCA and each year of the three-year RA cycle, including any
9 needs driven by sub-LCA constraints. The Residual Need will equal (Net LCR — CPUC
10 Jurisdictional LSE showings). Under CalCCA’s proposal that LSEs procure 90 percent of
11 their shares of Net LCR for Year 1, and assuming all LSEs meet that target, the Residual
12 for Year 1 will equal (10%*Net LCR),and may include other specific resources needed to
13 address sub-LCA constraints. The CAISO as Central Buyer will then procure some or all
14 of the remaining Net LCR amounts, as specified in Table 1 above, plus the ERR capacity
15 identified in Step 1 that has not been procured by an LSE for Year 1. Thus, for Year 1,
16 the process obtains at least 100 percent of the Net LCR by summing the procurement of
17 the Net LCR as specified in the table (e.g., for compliance year 1 90% met by LSE and
18 10% met by Central Buyer), and if necessary any additional resource procurement by the

²⁸ The LSE procuring excess ERR or sub-area resources would not be exempt from the costs actually incurred for the net procurement of the Central Buyer. Today, the CAISO tariff section 43.2.2.1 provides a “proportional credit,” meaning the procuring LSE is subsidizing other LSEs by paying for the RA while all LSEs will benefit by proportionally reduced CPM costs. This is a weakness in the current structure that we address in our transition proposal by offering a 1:1 credit instead of a proportionate credit (and limited to the ERRs) to create the proper incentives. Section 43.2.2.1 provides: “Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any CPM procurement costs under Section 43.8.3 reduced on a proportionate basis.”

1 Central Buyer to resolve sub-LCA constraints. When combined with POU procurement,
2 ERR procurement and CAM resources, at least 100% of the Total LCR is achieved.

3 Because the CAISO will have detailed knowledge of any sub-area needs and the
4 different effectiveness values of different resources, the Central Buyer step should result
5 in more efficient procurement of the Local Capacity than if LSEs were to procure 100%
6 of their Net LCRs as is done today. This should reduce the risk of overprocurement and
7 the likelihood of need for further CAISO backstop procurement for collective deficiency.
8 Costs of Central Buyer procurement would be allocated equitably among all responsible
9 LSEs,²⁹ including IOUs, POUs, CCAs and ESPs.

10 **B. Effectiveness of CalCCA's Proposed Transition Program**

11 CalCCA's proposed Transition Program effectively addresses many of the key
12 goals identified in Section I above. The program:

- 13 ✓ Abates collective overprocurement of Local RA and mitigates unnecessary
14 ratepayer costs by (i) providing early identification of ERR and other highly-
15 effective local resources, (ii) providing an opportunity for an LSE or group of
16 LSEs to procure the resources at a price lower than CAISO CPM Soft Offer
17 Cap, and (iii) providing an opportunity for the CAISO to act as a Central
18 Buyer to secure the residual remaining local resources that it deems necessary
19 for reliability as informed by individual LSE's procurement;
20
- 21 ✓ Ensures LSEs can act on their preferences for local resources, by providing
22 transparency on what resources are needed, with time to procure those
23 resources, while also narrowly defining the role of Central Buyer.
24
- 25 ✓ Allocates costs equitably across LSEs by avoiding cross-subsidies between
26 POUs and Commission-jurisdictional LSEs while also compensating
27 individual LSEs for procurement that benefits all LSEs;

²⁹ RMR costs are recovered through the transmission charges collected from utility distribution companies (UDCs), including POUs, served by the CAISO transmission grid. The UDCs then recover these costs from ratepayers through their retail transmission charges. CPM costs due to the collective deficiency are allocated *pro rata* on a load-share basis to each LSE serving load in the TAC area in which the deficient LCA was located. The LSEs then recover these costs from ratepayers through their retail generation rates.

- 1
- 2 ✓ Mitigates the impacts of planned and unplanned resource retirements and
- 3 reduces market uncertainty by encouraging LSEs to procure multi-year RA
- 4 contracts;
- 5
- 6 ✓ Aligns scale between buyers and sellers, by leaving an opportunity for group
- 7 procurement of larger resources and providing credit for LSEs that procure
- 8 ERR beyond their own needs; and
- 9
- 10 ✓ Reduces CAISO backstop procurement through transparency of sub-area
- 11 information, greater opportunity for LSEs to act on that information and
- 12 alignment of LSE economic interests to reduce overprocurement and
- 13 ratepayer costs.

14 Pending progress through the Long-Term Strategy, LSEs can individually focus on
15 decarbonization and DAC solutions in their local communities.

16 **C. Other Related Issues**

17 The success of the Transition Program hinges not only on Commission action, but
18 on coordination of existing processes in progress at the Commission, CAISO and CEC
19 and changes to CAISO tariffs. For example, the CAISO’s Flexible Resource Adequacy
20 Criteria Must Offer Obligation process (FRACMOO-2), will include a must offer
21 obligation for RMR so that flexible and system capacity attributes of RMR resources are
22 not lost. Specific reforms to the CPM and RMR processes also will be required,
23 including (1) adopting a definition of “Essential Reliability Resource,” (2) establishing a
24 process for a three-year ERR forecast, which will need to be coordinated with these
25 solutions, (3) coordinating central buying with the Commission’s multi-year program and
26 (4) facilitating payment to LSEs who purchase certain resources to the benefit of all
27 LSEs. In addition, coordination of Local RA and Flexible RA programs must be
28 ensured. All of these activities will drive the success of the Transition Program and
29 should be considered in another phase of this proceeding, in coordination with the
30 CAISO.

1 In addition, any central buying program, including the Transition Program, should
2 be reviewed on a regular basis to ensure it is achieving the desired goals. CalCCA
3 recommends that the first review take place 18 months after the commencement of the
4 central buying program, with annual updates thereafter.

5 **IV. LONG-TERM LOCAL RA STRATEGY**

6 The Track I Decision, following the Scoping Memo, appropriately focused on
7 reducing out-of-market procurement, using a multi-year Local RA program and increased
8 transparency to LRA needs. While this objective is important in the near term, solutions
9 should not end with improvements in the way Local RA is procured under local area
10 constraints. As long as these constraints exist, they will confer market power on certain
11 generators, preventing “competitive” procurement, and support continued reliance on
12 fossil fuel generation. The Commission and stakeholders must complement their efforts
13 to develop a multi-year program with a structured process toward the ultimate objective:
14 reducing or eliminating the local area constraints that cause out-of-market procurement in
15 ways that promote decarbonization and benefit DACs. CalCCA’s Long-Term Strategy
16 offers a practical approach to begin this discussion, relying on existing regulatory
17 mechanisms.

18 Distributed energy resources (DER) hold particular promise in relieving
19 constraints and thus play a central, although not exclusive, role in the Long-Term
20 Strategy. LCAs are typically densely populated areas, and most are currently
21 experiencing high rates of DER adoption, which over time changes the shape and size of
22 local-area demand and local-reliability needs. The latest indication of the potential for
23 DER is in the 2017-18 comprehensive transmission plan, which identifies \$2.6 billion

1 savings from eliminating or downsizing previously-approved transmission upgrades.
2 These reductions were for reliability upgrades to support constrained areas of the grid.
3 The Oakland Clean Energy Initiative, recently approved in the 2017-18 comprehensive
4 transmission plan, offers an example of the successful elimination of a fossil generating
5 plant that was needed for local reliability by a combination of grid assets and preferred
6 DERs. CalCCA's proposed Long-Term Strategy builds on state policies and trends by
7 advancing the growth of preferred resources, including DER, as a solution for local area
8 constraints.

9 The Long-Term Strategy focuses on two necessary areas of activity, which
10 together can accelerate elimination of market power in LCAs and replacement of fossil-
11 fuel generation with DER. At a policy level, the Commission must resolve open
12 questions that currently present barriers to deploying DERs. If these questions are
13 resolved, then cost-effective DER-based solutions can reasonably be evaluated and
14 adopted through the CAISO transmission planning process as non-wires alternatives
15 (NWA).

16 Movement toward the ultimate goal will take time, requiring reliance in the
17 interim on a multi-year program like CalCCA's Transition Program. Recognizing the
18 demands of time, CalCCA recommends adopting a process and general goals in its
19 decision in this Track to initiate longer-term strategies. CalCCA proposes adoption of its
20 Long-Term Strategy to provide such a framework.

21 **A. Removing Existing DER Barriers**

22 Two challenging areas must be addressed to facilitate the desired long-term
23 transition of California's grid reliability needs through DER deployment. One is the
24 matter of resource valuation and appropriate cost recovery, which requires regulatory

1 resolution by the Commission; the other has to do with operation of DERs as grid assets,
2 which will involve coordination between the CAISO and the relevant distribution utility
3 to support DER provision of transmission services.

4 DER deployed to offset local grid constraints have unique value that can be
5 compensated in different ways. In concept, if the DER deployment is fully intended for
6 offsetting the need for further transmission build-out, then such DER deployment could
7 be treated as a cost-based ATS (i.e., a transmission asset), thereby having its costs
8 recovered through transmission rates. One complication with the ATS path, however, is
9 that transmission assets become part of the CAISO controlled grid and as such are subject
10 to CAISO operational control. But to integrate DER as transmission assets will require
11 rules and procedures for coordination between the CAISO, the distribution utility and the
12 DER operator to ensure that the DER is able to deliver the needed transmission services
13 over the distribution system. To date such coordination procedures have not yet been
14 developed; developing such procedures will require collaboration between the CAISO,
15 the distribution utilities, and DER providers, with Commission review of any
16 implementation needs of the IOUs. Another complication to the ATS path for DER is the
17 need to establish methodology under the locational net benefits analysis (LNBA) element
18 of the DRP framework to quantify the transmission benefits of DERs. Policy resolution
19 by the Commission is important to ensure that DERs are fully compensated for the value
20 they provide.

21 Alternatively, the same DER may also help defer the need for distribution grid
22 build-out, therefore it may be appropriate to recover some of the build-out costs through
23 distribution rates. In this scenario the same DER would be engaged in “multi-use

1 applications” (MUA), *i.e.*, providing services to and receiving compensation from two
2 different entities: the CAISO with regard to the provision of transmission services, and
3 the distribution utility with regard to provision of distribution services.³⁰ This is an
4 attractive scenario because the ability to “stack” services and revenue sources would
5 increase the financial viability of the DER. However, it raises other unresolved MUA
6 issues, including priorities among service obligations when needs of the CAISO and
7 distribution utility may be in conflict, and measurement of the resource’s performance so
8 as to ensure that both the CAISO and the distribution utility compensate the resource
9 accurately for services received.

10 There are other cost allocation issues related to MUA that must also be addressed.
11 For example, if a storage resource procured by an IOU serves both generation needs and
12 distribution system functions, there is the potential for costs of generation services that
13 benefit the IOU’s bundled customers to be characterized as distribution costs and thereby
14 shifted to other LSEs’ customers. The specific matter of appropriate cost recovery for
15 energy storage MUA is currently under consideration in consolidated A.17-12-002 and
16 A.17-12-003 but may also require consideration for other resources.

17 The CAISO is presently exploring one type of MUA through its “Storage as a
18 Transmission Asset” stakeholder initiative. The scenario being considered is one where
19 the storage asset provides transmission services to the CAISO for part of its cost recovery
20 and participates in the CAISO market for the rest. This is an important first step toward
21 operationalizing MUA by allowing dual cost recovery mechanisms for the same facility,

³⁰ For details on rules adopted to date and open issues regarding MUA of storage resources see the Commission’s January 17, 2018 decision in Track 2 of the Energy Storage Proceeding, R15-03-011, in particular section 4.2 on open issues assigned to continuing working groups.

1 one through transmission rates and another through market revenues. But the scope is
2 limited to transmission-connected resources at this time, out of necessity to set aside the
3 matter of operational coordination with the distribution utility that a DER would require.
4 Consequently, there is still a need to develop a coordination framework to enable CAISO
5 operational control of a DER-based ATS.

6 Up to now, DER deployment has been compensated primarily through services
7 the DER provides to end-use customers (*i.e.*, typically installed behind the meter) and to
8 LSEs as energy and RA capacity resources, rather than as grid assets obtaining cost
9 recovery through distribution or transmission rates. Thus, for the next few years the
10 NWA path, which treats the DER solutions as resources rather than grid assets, will be
11 the most accessible path for DER to address local reliability needs without building new
12 transmission. The challenge here, though, is that even though DER in this scenario offset
13 the need for a transmission upgrade, they do not receive any compensation reflective of
14 the avoided cost of that upgrade and must rely entirely on contracts with LSEs and
15 revenues from the CAISO spot markets. An important open policy question is whether
16 and how DERs targeted to offset transmission upgrades for local reliability can receive
17 the avoided-cost value they provide, without shifting costs between bundled customers
18 and the customers of other LSEs.

19 As the Commission and various stakeholders consider and work through the
20 DER-related challenges of valuation, compensation, and operations, the Commission
21 could explore the merits of establishing incentives to further state policies through
22 preferred resource solutions to local reliability needs. One possibility could be for the
23 Commission to explore the merits of using Greenhouse Gas (GHG) allowance revenues

1 or other revenue sources as funding pathways for incentives to prioritize the build-out of
2 local preferred resources alternatives within DACs. Another opportunity could be the
3 potential for the CPUC and the CEC to coordinate and partner to structure incentives and
4 pilots of new DER technologies and control systems that would further reduce Local RA
5 needs.

6 The valuation and compensation questions surrounding DER, which the
7 Commission began to tackle in the IDER and DER proceedings, are complex and have
8 yet to be solved. CalCCA recommends that the Commission rededicate its efforts toward
9 a multi-agency approach, including the CAISO and CEC in a process aimed to resolve
10 the issue over the next year to support preferred resource solutions by late 2019.

11 **B. Implementing DER Solutions to Transmission Constraints**

12 The CAISO Transmission Planning Process (TPP) identifies transmission
13 upgrades that most cost effectively eliminate or substantially reduce LCA constraints,
14 including sub-area constraints. The Commission and the CEC inform the TPP by
15 providing a range of information, including scheduled power plant retirements, the IEPR
16 demand forecast and forecasts of load modifiers (energy efficiency, electric vehicle and
17 rooftop solar adoption), necessary to support the development of an accurate transmission
18 plan. For the current 2018-19 planning cycle the CAISO has already committed to
19 perform such studies for some of the LCAs, with a particular focus on eliminating fossil-
20 fuel generation and improving air quality in disadvantaged communities, and will provide
21 the results in fourth quarter this year. A coordinated initiative between the Commission
22 and the CAISO, addressing three key areas, could further enhance the TPP and enable
23 increased integration of DER solutions.

1 First, unless there is a driving reliability need for transmission upgrades, a
2 transmission upgrade to relieve LCA needs must be evaluated as an economic project.
3 This requires that the proposed transmission solution must provide net economic benefits
4 compared to the status quo. The CAISO evaluates economic transmission alternatives
5 using its Transmission Economic Assessment Methodology (TEAM). This methodology
6 considers a range of benefits in evaluating transmission alternatives, including
7 economically driven transmission evaluation criteria and other benefits (*e.g.*, limited
8 “public policy benefit”). Further coordination with the CAISO to ensure the
9 methodology fully considers the benefits and values represented by state policy goals
10 would improve the success of DER solutions.

11 Second, the TPP today does not provide sufficiently detailed information to allow
12 LSEs and developers to evaluate and propose suitable solutions. CalCCA’s Long-Term
13 Strategy contemplates that the CAISO would specify performance requirements that an
14 NWA or ATS must meet to avoid the transmission upgrade. Once the CAISO provides
15 this information in the course of its TPP, parties could propose an NWA or ATS to meet
16 the same need with local preferred resources. CalCCA proposes initially targeting areas
17 where central buying is required (due to market power concerns) and where local
18 reliability requires fossil-fuel resources that may not yet be scheduled to retire, with the
19 aim of ultimately removing the need for this procurement. LSEs could propose, perhaps
20 in partnership with DER developers or distribution grid operators, effective solutions that
21 help to enhance the affordability of clean energy resources in DACs.³¹

³¹ The 2016 EPIC grants for “Advanced Energy Communities” administered by the CEC offer examples of innovative clean energy and resilience project funding targeted to DACs and other communities. This program did not, however, specifically target reduction of Local RA

1 Third, timing considerations warrant exploration. A goal should be to ensure that
2 CAISO solicitations in the TPP process for NWAs and ATS are well timed and designed
3 to solicit preferred resource DER project solutions. Consideration must be given the
4 timing and interplay of the TPP and the IRP to maximize the development of alternatives
5 and accelerate implementation. Furthermore, any refinements to Commission-based
6 policies regarding DER valuation and compensation, discussed above, must be reached
7 expeditiously and implemented in sync with the TPP and IRP processes.

8 **C. Long-Term Strategy Benefits**

9 The Long-Term Strategy may be perceived as a formalized, natural extension of
10 current trends and the existing relationship between the Commission, CAISO and other
11 stakeholders. Looking closer, however, it changes the local reliability landscape in two
12 key ways, (1) more directly targeting preferred resource development to address local
13 reliability needs and (2) providing all stakeholders with the same information on
14 reliability requirements in a transparent and coordinated manner.

15 Currently the adoption of DER has not been targeted to offset local capacity or
16 transmission needs; the \$2.6 billion in reduced transmission needs has been a positive but
17 unintentional side effect of rapid DER growth through customer adoption. In contrast, the
18 Long-Term Strategy would build on presently unstructured DER adoption by explicitly
19 targeting preferred resource development, including additional DER adoption, to offset
20 LCRs. Importantly, however, the Long-Term Strategy would enable all LSEs (or groups
21 of LSEs) – not only IOUs -- to participate in developing solutions.

needs, which ought to be a consideration in designing future community-focused grant programs. For a summary of the awards see: <https://www.lgc.org/epic-approach-advanced-energy-communities/>

1 The Commission’s Resolution E-4909 issued earlier this year is a useful example
2 of targeted procurement of preferred resources to meet local reliability needs. The
3 Resolution authorized PG&E “to hold competitive solicitations for energy storage and/or
4 preferred resources, to meet specific local area needs in three specified subareas.”³²
5 Resolution E-4909’s implicit rationale for directing PG&E to procure the desired local
6 resources to the exclusion of other LSEs was apparently one of urgency: “Resources
7 procured pursuant to this solicitation must be on-line and operational by a date sufficient
8 to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather
9 River Energy Center, and Yuba City Energy Center – will not be renewed for 2019.”³³

10 In fact, however, none of the resources procured by PG&E will be in service on
11 time to meet this requirement of the Resolution. Of the total 567.5 MW of energy storage
12 PG&E proposes to procure, only 10 MW come on-line in October 2019 and the rest only
13 in December 2020,³⁴ so there will be no impact on local reliability needs until the 2021
14 RA compliance year. Directing the utility to undertake the desired procurement is
15 unnecessary and unfairly imposes costs on other LSEs and their customers over which
16 they have no input or control. Instead, the Commission should focus its efforts on
17 facilitating a broader opportunity for all LSEs and other stakeholders to procure local
18 preferred resources to offset grid reliability constraints that drive a continued reliance on
19 an aging and polluting fossil-fuel generation fleet. This principle is at the heart of
20 CalCCA’s Long-Term Strategy proposal.

³² Resolution E-4909 at 1.

³³ *Id.* at 9.

³⁴ PG&E Advice Letter 5322-E page 1.

1 **D. Long-Term Strategy Implementation**

2 The current 2018-19 CAISO transmission planning cycle provides an opportunity
3 to launch the Long-Term Strategy. In April, the CAISO announced a transmission study
4 plan for the current 2018-19 planning cycle aimed at eliminating or reducing as far as
5 possible LCRs in a selected set of LCAs, chosen with the objective of eliminating
6 reliance on local fossil-fuel resources.³⁵ The CAISO has indicated its intent to identify,
7 by fourth quarter of this year, the economic transmission projects that would be most
8 cost-effective in eliminating the Local RA needs. For those LCAs where the
9 transmission solution would provide net economic benefits, the CAISO would include
10 these projects in its 2018-19 comprehensive plan for Board approval. The current CAISO
11 approach does not, however, explicitly allow an opportunity for parties to propose an
12 NWA or ATS to meet the same needs, other than through the relatively brief stakeholder
13 comment period following the fourth quarter stakeholder meeting.

14 The CalCCA proposal would extend the window for submission of NWA or ATS
15 by stakeholders to the fourth quarter of the next TPP cycle – to the end of 2019 in this
16 first year iteration. This extension is particularly important for LCAs where existing
17 fossil-fuel resources are not yet scheduled to retire, and the CAISO’s identified
18 transmission upgrade may not meet the economic benefit-cost requirements for approval.
19 Allowing sufficient time to develop cost-effective preferred-resource alternatives could
20 be the pivotal factor in eliminating the need for the local fossil resource.

21 The Long-Term Strategy anticipates the CAISO’s completion of its current
22 assessment of the selected LCAs this year. Over the following two annual transmission

³⁵ See the CAISO’s stakeholder presentation at:
<http://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf>

1 planning cycles the CAISO would similarly study all LCAs in the system. Design of
2 NWA/ATS proposals by stakeholders could begin by the end of 2018 for the LCAs the
3 CAISO studies this year, with the DER-based NWA/ATS potentially implemented within
4 the two to three years following CAISO assessment and selection of the preferred
5 alternatives in the 2019-20 TPP cycle. Thus, the LSEs would use the results of the
6 CAISO planning studies to participate in developing NWA/ATS to address local
7 reliability needs, and would include such projects in their IRPs. Any such development
8 of NWA or ATS would also be included in the LSE's IRPs. At the Commission level the
9 combination of all LSE IRPs would then reflect the Long-Term Strategy to implement
10 local preferred resources to ensure local area reliability while phasing out fossil-fuel
11 resources that have been needed for this purpose, rather than assuming indefinite
12 continued reliance on the non-OTC fossil resources to support local reliability.

13 **V. CONCLUSION**

14 Near-term implementation of CalCCA's multi-year Transition Program promises
15 to change the way in which Local RA is procured, with the aim of reducing out-of-market
16 procurement and overprocurement thereby reducing Local RA procurement costs overall.
17 This approach not only will achieve these initial goals, but will avoid the need for
18 material structural changes by capitalizing on existing procurement mechanisms and
19 institutions. The evolution of Local RA procurement should not stop, however, with
20 improvements in the way Local RA is procured in the short term. As long as local
21 constraints exist, they will confer market power on certain generators who will be able to
22 demand sufficient payment to run indefinitely. Expecting resources with partial or
23 complete market power to negotiate "competitive" rates that resemble the short-term

1 price for Local RA is unrealistic. The Commission must thus complement the Transition
2 Program with a structured step toward the ultimate objective: reducing or eliminating the
3 local area constraints that cause out-of-market procurement through deployment of
4 resources that promote decarbonization and benefit DACs. CalCCA's Long-Term
5 Strategy offers a framework to begin this journey. For these reasons, CalCCA
6 recommends the adoption of the Transition Program and the Long-Term Strategy.

APPENDIX A

Local Reliability

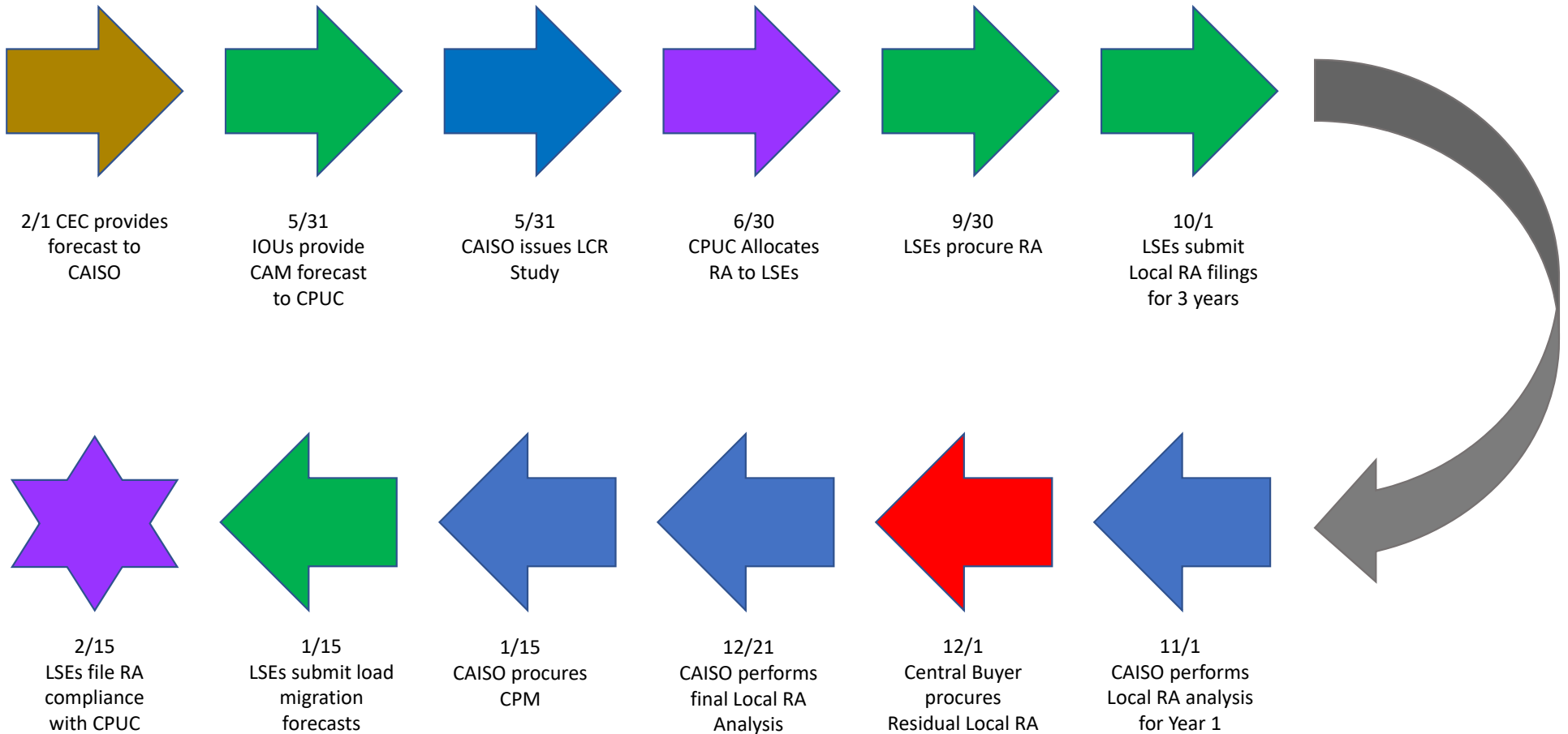
Transition Program

Process Overview and Timeline

Local RA Procurement Process – April 1 Compliance Year

Step	Due Date	CPUC	CAISO	CEC	CPUC LSEs	Munis	Central Buyer	Activity
0	1-Feb		●	●				CEC provides to CAISO peak demand forecasts used for System and Local RA.
1	31-May	●			●			IOUs provide CAM forecasts for each year of the upcoming RA cycle to CPUC
2	31-May	●	●					CAISO completes 3-year forward Local and Flexible Capacity Study and provides the list of ERR resources (years 1 through 3) to CPUC.
3	30-Jun	●	●		●	●		CPUC allocates net local RA requirements (years 1 through 3) to CPUC-Jurisdictional LSEs, and CAISO allocates net local RA requirements (years 1 through 3) to Munis
4	30-Sep				●			CPUC-Jurisdictional LSEs procure required percentages of their shares of Net LCR for each of the three years.
5	1-Oct	●	●		●	●		CPUC-Jurisdictional LSEs and Munis submit RA filings to CPUC and/or CAISO, demonstrating 90% of net LRA requirements for year 1, 90% of net LRA requirements for year 2 and 80% of net LRA requirements for year 3. No LSE cure period will be provided.
6	1-Nov		●					CAISO performs local RA Residual needs assessment for year 1 and announces results. Assessment is based on the need to achieve 100% of local RA need for year 1, including addressing any problematic sub-local-area constraints
7	1-Dec						●	Central Buyer procures the Residual, including ERR capacity not already procured by LSEs
8	21-Dec		●					CAISO performs final Year-Ahead local RA assessment to ensure that all Year 1 Local RA needs have been procured. Notifies LSEs of any deficiencies.
9	15-Jan		●		●	●		If needed, CAISO uses CPM backstop authority to procure the remaining required Year 1 Local RA resources, and CAISO accordingly allocates RA credits to LSEs and Munis
10	15-Jan		●	●	●	●		January Year 1 load migration forecasts submitted by CPUC-Jurisdictional LSEs and Munis to CPUC and/or CEC
11	15-Feb	●	●		●	●		January Year 1 Month Ahead RA filing (T-45). CPUC-Jurisdictional LSEs and Munis submit RA filings to CPUC and/or CAISO

CalCCA Proposed Local RA Timeline – April 1 Compliance Year



WITNESS QUALIFICATIONS

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Dr. Richard McCann

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Résumé

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Experience

Independent Consultant (December 2017 to present)

Current focus is on various aspects of power system evolution to high levels of renewable generation and distribution-connected energy resources (DER). Areas of expertise include: wholesale market design; market participation by DERs and DER aggregations; multi-use applications of DERs; coordination of transmission and distribution operations, markets and planning; distribution system operator (DSO) models for distribution utilities; transmission planning policy and alternative transmission and non-wires solutions; international comparison of TSO-DSO coordination models; community energy systems and microgrids; whole-system grid architecture.

Recent projects include:

Participation in and filing of individual comments on the Federal Energy Regulatory Commission technical conference on “Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators”; Docket RM18-9-000; June 2018

Co-author of “Alternative Transmission Solutions: A Roadmap to the CAISO Transmission Planning Process”; Center for Renewables Integration; March 2018;
<https://www.center4ri.org/publications/>

Co-author of “Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design”; prepared for the Australian Energy Market Operator (AEMO); May 2018

Individual comments to the California Public Utilities Commission in response to the October 31, 2017 informal public workshop on California Customer Choice; November 2017;
[http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy - Electricity and Natural Gas/Lorenzo%20Kristov%20Comments.pdf](http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Lorenzo%20Kristov%20Comments.pdf)

California Independent System Operator (CAISO) (May 1999 to November 2017)

Principal, Market and Infrastructure Policy (2004-17); Manager, Market Design (1999-2004)

Led major market design and infrastructure policy initiatives, which entailed leading internal cross-departmental teams to develop proposals, conducting public stakeholder meetings to gather input, revising proposals to reflect stakeholder concerns, presenting final proposals to CAISO Board of Governors for approval, working with CAISO Legal department to prepare FERC filings (detailed proposal description and rationale, tariff revisions and expert testimony), appearing at FERC technical conferences, addressing FERC-ordered compliance requirements and supporting internal departments to implement FERC-approved market elements and tariff changes. Most initiatives were CAISO-initiated, but some were in compliance with new FERC rulemakings (e.g., Order 1000).

A central requirement of this position has been to apply whole-system thinking to structure each initiative to align the immediate needs of the problem to be addressed, the diverse objectives and concerns of the stakeholders, relevant regulatory constraints and requirements, and the priorities and responsibilities of the CAISO as a whole and its affected functional departments: grid operations, infrastructure planning, market performance.

Some specific major projects:

Initiated and led ongoing staff working group between CAISO and distribution utilities to identify needs and develop procedures for operational coordination at the transmission-distribution interfaces to enable distribution-connected resources (DER) and aggregations to participate in CAISO markets. (2016-17)

Represented CAISO in ongoing trans-Atlantic working group to describe and compare US and European approaches to transmission-distribution interface coordination with high DER. (2017)

Led CAISO-CPUC staff collaboration to develop a framework for multiple-use applications of energy storage, as part of the CPUC's Energy Storage Track 2 proceeding. (2016-17)

Led initiative to address cost allocation for existing transmission infrastructure and new projects under an expanded ISO/RTO structure for the western region. (2015-16)

Redesign of CAISO's new resource interconnection procedures to manage the large volume of new interconnection requests driven by anticipated procurement to meet California's Renewable Portfolio Standards (RPS), including the interconnection study process, management of the interconnection queue, and coordination between generator interconnection and transmission planning processes. (2011-12)

Redesign of CAISO's transmission planning process to address impacts of RPS procurement on transmission needs to deliver energy and capacity from renewable generation facilities; included addition of a new public-policy-driven category of transmission, coordination with state agencies to identify RPS procurement patterns that would drive transmission needs, and a competitive solicitation process for third party developers to build, own and operate transmission projects. (2009-10)

Initiated and led internal CAISO Strategic Roadmap Process, a cross-departmental team to map energy industry trends nationally and in the west and identify highest priority areas for CAISO focus in the coming years; performed in 2009, this roadmap led directly to the major redesigns of transmission planning and generator interconnection procedures noted above.

Comprehensive redesign of CAISO markets following the 2000 energy crisis to implement locational marginal pricing (LMP) market structure, including day-ahead and real-time markets, financial transmission rights, and integration of pre-existing bilateral transmission contracts. (2002-09)

California Energy Commission (CEC) (December 1994 to April 1999) Energy Economist

Represented the CEC in state proceedings and collaborative working groups to design the new provisions needed to implement the retail choice elements of California's electric restructuring legislation, AB-1890. Specific subjects included qualification of retail direct access providers, definition of "meter data management agent" (MDMA) function, and creation of distribution node identifier scheme for tracking changes of end-use customer, retail provider and metering device at each end-point of the distribution system. Facilitated several working group activities and co-authored working group reports; co-authored CEC regulatory filings at the CPUC.

Fulbright Scholar, Indonesia (April 1993 to December 1994)

As an independent researcher, met with Indonesian government officials, private companies, consultants, USAID and World Bank personnel to describe and assess economic and structural

landscape for direct foreign investment in electric power infrastructure needed to support and sustain industrial growth.

Education

PhD Economics, University of California Davis, 1994

MS Statistics, North Carolina State University, 1969

BS Mathematics, Manhattan College, 1967

Relevant recent articles

Kristov et al (2017) “Coordination of transmission and distribution operations in a high distributed energy resource electric grid;” presenting results of collaborative working group between CAISO and electric distribution utilities; http://gridworks.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

Kristov et al (2017) Primary author of “Comments of the California Independent System Operator Corporation” on FERC’s Notice of Proposed Rulemaking (NOPR) to remove barriers to participation of electric storage resources and distributed energy resource aggregations in ISO/RTO wholesale markets; provides detailed descriptions of CAISO provisions for storage and DER aggregations to participate in wholesale market, and T-D interface coordination arrangements with distribution utilities; http://www.aiso.com/Documents/Feb13_2017_Comments-ElectricStorageParticipation_MarketsOperated_ISOs_RM16-23_AD16-20.pdf

Kristov, De Martini & Taft (2016) “Two visions of a transactive electric system,” published in IEEE Power & Energy Magazine, May-June 2016; http://resnick.caltech.edu/docs/Two_Visions.pdf

Kristov (2015) “A future history of tomorrow’s energy network,” published in Public Utilities Fortnightly, May 2015; https://www.academia.edu/12419512/A_Future_History_of_Tomorrows_Energy_Network

De Martini & Kristov (2015) “Distribution systems in a high distributed energy resources future: planning, market design, operation and oversight,” Lawrence Berkeley National Lab series on Future Electric Utility Regulation; https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf

Kristov et al (2017) Primary author of “How Transmission Cost Recovery Through the Transmission Access Charge Works Today: Background White Paper”; <http://www.aiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf>

Kristov et al (2016) Primary author of “Transmission Access Charge Options for Integrating New Participating Transmission Owners: Draft Regional Framework Proposal”; <http://www.aiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf>

Kristov & De Martini (2014) “21st Century Electric Distribution System Operations”; <http://smart.caltech.edu/papers/21stCElectricSystemOperations050714.pdf>

Taft, De Martini & Kristov (2015) “A reference model for distribution grid control in the 21st century,” Pacific Northwest National Lab; https://gridarchitecture.pnnl.gov/media/advanced/Distribution%20Control%20Ref%20Model_v1.1_final.pdf



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Professional Experience

M.Cubed, Partner, 1993-2008, 2014-present
Aspen Environmental Group, Senior Associate, 2008-2013
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1986-1992
Dames & Moore, Economist, 1985-1986

Academic Background

PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Dr. McCann has analyzed many different aspects of energy utility and market operations in California. He has testified numerous times before the CPUC on impacts of electricity rates on agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, competitive fuel choices, and proposed drought-mitigation policies. He has testified on the appropriate level of exit fees for community choice aggregators, and appropriate protection of solar project investment by customers. He also testified before the Federal Energy Regulatory Commission in the California energy crisis Refund Proceeding. He has worked with the California Energy Commission to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration. For the CEC, he examined the potential consequences of decommissioning the dams on the Klamath River, and for the SWRCB, the changes in greenhouse gas emissions from hydro licensing conditions. He also led the modeling efforts on behalf of the California Public Utilities Commission to assess the environmental impacts of proposed generation plant divestitures.

Projects

Energy, Hydropower and Utilities

Regulatory Analysis and Support, Sonoma Clean Power (2016-present). Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Regulatory Analysis and Support, CalChoice (2017). Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present). Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature. Analyzed various aspects of electric industry restructuring; proposed innovative pricing options; examined marginal cost principles and applications, and testified in a large number of energy related hearings. Developed innovative rate

allocation methodology that incorporated regional marginal costs and value of service planning based on the Pacific Gas and Electric Co. Area Cost Study.

Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-present).

Testified before the California Public Utilities Commission on

Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present). Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing “master-meter/submeter credits” provided to private mobile home park utility systems.

Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present). Prepared petition that opened a rulemaking to facilitate transfer of master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.

Community Solar Gardens Testimony, Sierra Club (2014). Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.

Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014).

Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities’ most recent general rate case filings.

Southern California Edison v. State of Nevada Department of Taxation, Nevada Attorney General’s Office (2013-2014).

Testified on whether the sales tax imposed on coal delivered to SCE’s Mohave Generating Station created a competitive disadvantage for SCE in the Western power market during the 1998-2000 period.

Professional Affiliations

American Agricultural Economics Association
Association of Environmental and Resource Economists
American Economics Association

Civic Activities

Member, City of Davis Utilities Rate Advisory Commission
Former Member, City of Davis Community Choice Energy Advisory Committee
Co-Chair, Cool Davis Energy Steering Committee
Member, Western Manufactured Housing Communities Association Utilities Task Force
Former Member, City of Davis Citizens Electricity Restructuring Task Force
Former Member, Yolo County Housing Commission
Member, Phi Beta Kappa Honorary Fraternity

SHEHZAD WADALAWALA

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Work Experience

The Energy Authority (“TEA”), Oakland, CA

Client Services Manager (7/16-present)

- Serve as Product Owner relating to the design, development and implementation of day-ahead and real time market services for TEA’s CAISO operations;
- Work with clients and TEA’s Portfolio Management and Analytics groups to define portfolio positions and develop hedging strategies
- Support client procurement activities by developing solicitation materials, including protocols, offer forms and contract templates and by providing assistance evaluating offers

SolarCity, San Francisco, CA

Sr. Manager, Grid Engineering Solutions (8/15-4/16)

- Led preparation of response to Innovative Storage Models RFI for ConEdison and Orange & Rockland
- Evaluated partnership opportunities with Community Choice Aggregations (CCAs), Electric Service Providers (ESPs), Municipal Utilities and Investor Owned Utilities (IOUs) focused on Distributed Energy Resources (DERs)
- Supported utility scale development team in understanding target wholesale markets

California Clean Power, Windsor, CA

Associate Director of Procurement (3/15-8/15)

- Authored key technical sections of Feasibility Reports for Community Choice Aggregation (CCA) formation; jurisdictions analyzed include Lake and Humboldt County
- Analyzed utility tariffs and filings to determine risks to company business model with particular focus on Non-Bypassable Charges (NBCs) such as the Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM)
- Identified potential Scheduling Coordinator (SC) Agents and negotiated contract for services

University of California Office of the President, Energy Services Unit, Oakland, CA

Associate Wholesale Electricity Program Manager (2/14-3/15)

- Led key implementation efforts for The Regents of the University of California to become its own Electric Service Provider (ESP) and serve its Direct Access campus accounts beginning January 2015
- Managed the Scheduling Coordinator (SC) contract including all relevant activities with the California Independent System Operator (CAISO) to be ready to submit daily load and generation schedules
- Solicited, selected and managed a Back Office provider; all eligible accounts were successfully transferred in January 2015
- Tracked, prepared and submitted numerous regulatory filings at the California Public Utilities Commission (CPUC), California Energy Commission (CEC), California Independent System Operator (CAISO), California Air Resources Board (ARB); all obtained approval
- Developed Request for Offer protocols for long-term solar solicitation; served on the evaluation committee and member of negotiating team that executed two 25-year Power Purchase Agreements (PPAs) totaling 80 MW of capacity

Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA

Manager, Commodity Transactions (4/12-1/14)

- Managed a team of five employees responsible for:
 - 1) Preparation of Resource Adequacy (RA) Annual and Monthly Compliance Filings
 - 2) Execution of RA Request for Offers (RFOs)
 - 3) Implementation of the Electric Hedging Program
 - 4) Management of the Congestion Revenue Rights (CRRs) Portfolio
 - 5) Procurement of GHG Compliance Instruments
 - 6) Compliance with Energy Delivery Requirements for out-of-state Renewable Resources
- Prepared strategy and informational papers on highly technical material for members of the Risk Policy Committee (RPC)

Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA

Principal, Short Term Portfolio Management (5/11-4/12)

- Led Resource Adequacy Request for Offers (RFOs); coordinated with Portfolio Management, Contract Management, Credit Risk, Legal and Compliance teams to ensure sufficient procurement to meet Resource Adequacy Requirements and ensure full cost recovery for procurement costs
- Coordinated talking points and written comments for AB32 Regulation (“Cap and Trade”) for commercial team; resulted in favorable outcomes for PG&E most notably, obtaining fungibility of compliance instruments within compliance periods
- Contributed extensively to development of new Combined Heat and Power (CHP) Tolling Power Purchase Agreement (PPA), including recommending significant changes to Uninstructed Imbalance Energy and GHG Obligation Settlement sections and led development of a new Operational Flow Order (OFO) section in response to feedback from Electric Fuels Management about the increasing frequency of OFOs and associated commercial risks

Pacific Gas and Electric Company – Market Design and Monitoring, San Francisco, CA

Supervisor, Market Analysis (6/10-5/11)

- Supervised production, presentation and distribution of Market Redesign and Technology Upgrade (MRTU) Quarterly Report that included detailed discussion of CAISO market performance, key market issues, and financial risks for PG&E; presented to Senior Management
- Developed and supervised implementation of a comprehensive Convergence Bidding monitoring framework collaborating with Short Term Electric Supply; spearheaded analysis that identified gaming behavior and resulted in PG&E successfully advocating for suspension of convergence bidding at intertie locations.
- Educated Energy Procurement staff on CAISO markets through biweekly Market Talk Seminar Series that covered a range of CAISO topics including Convergence Bidding, Participating Intermittent Resource Program (PIRP), Oversupply Conditions and Negative Pricing, Congestion Revenue Rights (CRR’s), Locational Marginal Prices (LMP’s), Co-Optimization of Energy and Ancillary Services, Residual Unit Commitment (RUC), and Real Time Imbalance Energy Offset

Pacific Gas and Electric Company – Short Term Electric Supply, San Francisco, CA

Senior Analyst (7/08-6/10)

- Spearheaded development of business case for company participation in Convergence Bidding, including coordinating Risk Policy Committee (RPC) draft, contributing to upfront and achievable standards drafts, working with Information Technology and the Project Management Office to develop implementation cost estimates and collaborating with Market Risk Management, Market Design and Analysis and the Legal Department to identify potential risks
- Reformulated day-ahead optimization problem as a multi-day optimization reducing uneconomic cycling of thermal resources and improving commitment process for long-start resources
- Designed analytical tools and trading guidelines for real-time traders to manage price exposure

Pacific Gas and Electric Company – Quantitative Analysis, San Francisco, CA

Quantitative Analyst (6/04-7/08)

- Designed Microsoft Excel template that calculated energy values, risk-hedging metrics and generates summary sheets for physical assets (evaluated Gateway Generation Station project with template)
- Reformulated day-ahead scheduling optimization problem implemented in Short Term Electric Supply to include startup costs, ramping constraints and ancillary services increasing scheduling efficiency
- Developed gas asset strategy model to simulate cost outcomes for different portfolios of pipeline capacity and storage (model was used to evaluate investment in Ruby Pipeline capacity)

Education

University of California, Berkeley

PhD ABD Industrial Engineering and Operations Research (August 2003 - June 2008)

B.S. Industrial Engineering and Operations Research, August 2003; Public Policy Minor

Merits

8/99-5/03

University of California Regents’ & Chancellor’s Scholarship

10/01-5/03

Alumni Emerging Leader Scholarship