BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON PROPOSED DECISION ON
WORKING GROUP 1 ISSUES 1-7 AND 11

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON PROPOSED DECISION ON WORKING GROUP 1 ISSUES 1-7 AND 11

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] submits the following comments on the proposed *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, issued on September 6, 2019 (Proposed Decision or PD).

I. INTRODUCTION AND SUBJECT MATTER INDEX

The Proposed Decision addresses Power Charge Indifference Adjustment (PCIA) Scoping Memo issues related to the PCIA annual true-up (Issues 1-3), forecasting (Issues 4-5), the value of unsold resource adequacy resources (Issues 6-7) and billing determinants (Issue 11). It adopts certain proposals by CalCCA and Pacific Gas and Electric Company (PG&E), Working Group 1 (WG 1) co-leads, with modifications and decides two PCIA issues that remain unresolved by WG 1: (1) the price set for unsold Renewable Portfolio Standard (RPS) attributes and (2) the price set for unsold Resource Adequacy (RA) attributes.

CalCCA partly supports the Proposed Decision, but recommends the following modifications:

- ✓ The Commission should defer any decision on whether or how to include long-term fixed price power purchase agreements (PPAs) in the RPS benchmark until after conclusion of

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

a public process establishes that their inclusion will be feasible, consistent with D.18-10-019;

- ✓ All unsold RPS attributes should be valued at the RPS benchmark, recognizing the value of these attributes to bundled customers and ensuring consistency with D.18-10-019;
- ✓ All unsold RA attributes should be valued at the price floor set by the IOU in its sales process for such attributes to the extent the price floor exceeds the amount required to avoid penalties;
- ✓ For RA to qualify as unsold in calculating the market price benchmark, an IOU must offer that RA to the market by the end of August preceding the compliance deadline for the relevant year to avoid prejudice to other load-serving entities (LSEs). Otherwise unsold amounts are treated as retained and valued at the Market Price Benchmark (MPB), precluding a zero or *de minimis* valuation in the RA benchmark; and
- ✓ The Commission should clarify certain issues regarding forecasting and true up methodology.

Proposed changes to findings of fact, conclusions of law and ordering paragraphs are provided in Appendix A.

II. THE COMMISSION SHOULD ADOPT THE CO-LEADS' RECOMMENDATION TO BASE THE RPS ADDER ON INDEX PLUS TRANSACTIONS AND DEPART FROM THIS APPROACH ONLY IF A FEASIBLE METHODOLOGY IS ESTABLISHED THROUGH A PUBLIC PROCESS

The Proposed Decision adopts the co-leads' proposal for calculating the RPS Adder based on four quarters of Portfolio Content Category 1 index-plus contracts. CalCCA supports this portion of the Proposed Decision.

Additionally, however, the Proposed Decision finds: "Incorporating fixed-price bundled transactions into RPS Adder calculations is expected to produce more accurate results and is ultimately the proper approach."[2] The Proposed Decision further directs Staff "to propose a method to include long-term fixed-price transactions in calculating the RPS Adder by December 2020."[3] When read together, these portions of the Proposed Decision appear to commit the Energy Division Staff to developing a methodology to incorporate long-term fixed-price transactions into the RPS Adder, to take effect in 2021. While the PD itself recognizes "[t]here are technical challenges" to this approach — a fact acknowledged by TURN — it downplays

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[2] PD, Finding of Fact 6 at 45.

[3] PD at 12, and Ordering Paragraph 1(c), at 53.

those challenges. It further concludes that an index-plus approach will not reflect the evolution of the market toward long-term contracts.[4] As discussed below, the co-leads undertook extensive efforts to develop a method for including long-term fixed price contracts in WG 1. We found contrary to claims of greater accuracy, this approach would be technically challenging, and re-introduce the sort of administrative assumptions and non-market approaches to valuation that D.18-10-019 eschewed.

A. The Appropriate Input for the RPS Adder Is "Index Plus" Transactions

The co-leads proposed, and the PD adopts for 2020, the use of "index-plus" transactions as the appropriate input for the RPS Adder. Index-plus transactions have the following virtues:

- Index-plus is the current market standard method for transacting for RPS supply among IOUs and CCAs. This is how IOUs are selling from their portfolios.
- Index-plus deals are short-term, and so reflect current market prices for a particular delivery year, with none of the temporal complexity that long-term deals introduce.
- Index-plus deals explicitly price separately for energy and RPS, avoiding the need to tease the value of multiple attributes out of a single price.
- Index-plus deals are generally not generator specific, and so avoid the need to engage in project-specific analysis of a generation profile, or node-specific pricing analysis.

For the Final RPS Adder, the PD proposes to rely "on index-plus contracts executed in year (n-1), and the first through third quarter of year n for delivery in year n…."[5] CalCCA agrees with this approach, providing for the most recent data available to determine the RPS market price benchmark – a benchmark that is intended to reflect current market prices.

B. The Working Group Co-Leads' Extensive Efforts to Develop a Method for Including Long-Term Fixed-Price PPAs into the RPS Adder Led to the Conclusion that Doing So Is Infeasible

CalCCA and PG&E devoted substantial effort to incorporating long-term fixed-price transactions into the RPS Adder. We concluded that doing so was infeasible in light of

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4 PD, Finding of Fact 3 at 45.

5 *Id.*, Ordering Paragraph 3.a at 52.

D.18-10-019's requirements to use (a) recent, (b) market-based, (c) prices for particular power attributes.[6]

The mismatch between the D.18-10-019 framework and long-term fixed price contracts is fundamental. Decision18-10-019 requires valuation of individual attributes (brown power, an RPS adder, and an RA adder) for a particular time (year N) from recent contracts (executed within the last two years) for all types of generators. In contrast, long-term fixed-price PPAs, particularly for new construction, value all of the attributes from an individual power plant together at a single price for numerous years, even decades. There is no separate valuation of individual outputs — no separate RA price or RPS price or brown power price. Just a single $/MWh energy price. Further complicating matters, prices are held constant over many years (sometimes with periodic step-ups, more often not). And value for a particular project will depend on its location with the CAISO system and its generation profile. Teasing out point estimates of the value of individual attributes at a particular point in time from agreements for a bundle of attributes over a long period of time requires addressing and disentangling the temporal, locational, and technological factors in play for each PPA. We will take each of these concerns in turn.

Long-term fixed-price PPAs are, as the name implies, for a long term, and do not readily lend themselves to valuation for a single year. The parties who negotiated the deal may have offered a discount in early years in return for higher payments in later year, or vice versa, and there is no way to tell from the contract. Thus, to derive a value for a particular year requires the sort of administrative assumptions (*e.g.*, assumption of a discount rate, or a forward price curve) that D.18-10-019 was supposed to leave behind. There is also a temporal challenge. For new construction, there is often more than two years between the contract execution date and the expected commercial on-line date (COD). If we stay within the time limits imposed by D.18-10-019's stated desire to use recent transaction data (contracts executed no earlier than "n-2", in the parlance of Appendix A), many or even most long-term fixed-price PPAs will not be eligible for inclusion in the RPS Adder. Extend the time frame for inclusion, and you are no longer looking at just recent transactions. Moreover, any cut-off past n-2 (the last full calendar year for which data are available at the time of the rate forecast) is essentially arbitrary.

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6 *See* D.18-10-019, Appendix A.

Thornier still is the challenge of extrapolating the value of any one attribute from a contract that provides for *all* attributes for a single price. A long-term fixed-price PPA will generally provide for the entire output of a plant (energy, RPS, RA, and anything else) for a single $/MWh. It is impossible to determine from the PPA itself which portion of that price is attributable to energy, or green attributes, or RA, or other attributes. Doing so requires, again, the sort of administrative assumptions that D.18-10-019 was supposed to leave behind in favor of actual market transaction data. It requires subtracting out an administratively established energy value, and subtracting out an administratively established RA value converted from $kw/month to $/MWh using some selected estimated load carrying capacity value.

Finally, the type of generation and the location of the resource play a part in determining resource value. Renewable generators' output will vary substantially depending on the project technology type (*e.g.*, wind or PV solar) and the location of the project (insolation and wind characteristics vary materially depending on location). Prices also vary depending on the CAISO node at which a plant interconnects. Then there is the added complication of co-located storage. To address these variables again requires the type of administrative assumptions and simplifications (*e.g*., use of a generic generation profile, aggregation of nodal prices) and risks a mismatch with actual market structures that D.18-10-019 was supposed to leave behind.

Before the Commission concludes that inclusion of long-term fixed price PPAs in the RPS benchmark is feasible, much less the "better approach,"[7] further work is required. The Commission should substantially modify the PD's recommendations for gathering data and developing an alternate methodology, as discussed below.

C. Any Refinements to the RPS Benchmark Should Be Developed Through a Transparent Public Process

Even if conceptually incorporating long-term fixed-price PPAs into the RPS market price benchmark were *desirable* notwithstanding D.18-10-019's focus on recent market transactions for specific power attributes, the Commission should first establish that it is *feasible* within D.18-10-019's framework. As noted above, including long-term fixed price PPAs in the RPS benchmark is fraught with challenges. CalCCA recommends that the Commission undertake further public processes before determining that a new methodology will be employed for the

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[7] PD, Finding of Fact 6 at 45.

2021 RPS Adder to ensure sufficient opportunity to understand and address the issues encountered by WG 1.

The Commission should invite Staff to develop a methodology for modifying the RPS benchmark to include long-term fixed-price PPAs *if and only if such a methodology can be squared with D.18-10-019*. The Proposed Decision should be revised to clarify that the December 2020 date is a deadline for Staff to put forward its proposal, rather than a date for implementation of such a proposal. We recommend specific changes to the PD in Appendix A.

D. The Scope of Monitoring Data Should Not Be Presumed to Suggest a Proper Window of Time for Transactions to Develop the RPS Adder

The PD proposes collection of data from a broad window of time to allow Staff to inform a modified benchmark.[8] It provides:

> Information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2) will help Staff monitor the impact of fixed-price transactions on the RPS Adder and propose a method to incorporate fixed-price contracts into the RPS Adder calculations.[9]

Gathering this information may be appropriate for "monitoring" whether it is advisable to shift to including long-term fixed-price contracts in the RPS Adder. However, using prices from such a wide window for a benchmark intended to reflect ***current*** RPS market prices would be contrary to D.18-10-019. Decision18-10-019 limits the relevant transactions for the Forecast RPS Adder to (at most) those executed two years prior to a single delivery year, consistent with its emphasis on "accurate' (read: recent) prices. We appreciate that the windows of time covered by the monitoring procedures are not intended to provide the windows for data to be employed in any modified benchmark.

III. ALL UNSOLD RPS ATTRIBUTES SHOULD BE VALUED AT THE RPS BENCHMARK TO RECOGNIZE THE VALUE OF THESE ATTRIBUTES TO BUNDLED CUSTOMERS AND CONFORM TO D.18-10-019

The PD concludes that "the value of unsold RPS resources should be zero" for purposes of the PCIA benchmark calculation.[10] It reasons that "[u]nsold RPS products also may well have

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[8] *Id.,* Finding of Fact 7 at 46.

[9] *Id.*

[10] PD, Conclusion of Law 20 at 51.

no value if they expire or are banked by an LSE that is not able to use them for compliance."[11] It acknowledges, however, that the attributes may have value if "used by the IOU to exceed compliance requirements; retired to an IOU's RPS bank for hypothetical future use; or sold as lower value."[12]

The PD's conclusion is inconsistent with D.18-10-019. Decision18-10-019 says nothing about zero-value treatment for unsold RPS, in contrast to unsold RA. Reflecting D.18-10-019's silence on the matter, the Scoping Memo did not direct or mention resolution of this issue. Unsold RPS has yet to be shown to be a problem for any IOU. Moreover, the PD fails to recognize the clear and immediate value to IOUs of holding these attributes for their bundled customers as compliance insurance and carbon-free energy in the Power Content Label or Clean Net Short. The Commission should reject the PD's proposal and require the IOU to value unsold RPS attributes at the benchmark value. We expand on each of these arguments below.

First, nothing in D.18-10-019 provides for valuation of unsold RPS at zero. Decision 18-10-019 mentions unsold RA capacity eight times in its body text, and also contains an ordering paragraph addressing such capacity.[13] Not a single mention is made in D.18-10-019, however, of valuing "unsold RPS" at zero. Consistent with D.18-10-019, the February 1, 2019 Scoping Memo addresses unsold RA,[14] and makes absolutely no mention of treatment of unsold RPS. There is no procedural foundation basis for the Commission to adopt the PD's proposal to value unsold RPS at zero.

Beyond procedural concerns, the PD fails to account for the immediate value of unsold RPS to provide bundled customers. CalCCA pointed out in comments on the final Working Group 1 Report that unsold RPS "has value from the moment of generation," stating:

> Under existing rules, the IOU takes credit for the RPS attributes in the Power Content Label in the year generated, not in some future year. Similarly, RPS attributes provide value under the Clean Net Short proposal in the year of generation. Finally, unsold and

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[11] PD, Finding of Fact 19 at 47.

[12] PD, Finding of Fact 18 at 47.

[13] D.18-10-019 at 25, 71, 73, 80, 121, 149, 153-54 (Finding of Fact 4), and 160 (Ordering Paragraph 1.c).

[14] *Phase 2 Scoping Memo and Ruling of Assigned Commissioner* (Scoping Memo) at 4, Issue 7 ("D.18-10-019 specified that 'a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB.' Are further parameters needed to define a de minimis price, and if so, what are these parameters?").

> retained RPS can be used for bundled customers' compliance obligations in later years.[15]

Moreover, the unsold RPS provides a "buffer" for compliance insurance in the future, should changes in load or the RPS market occur. Indeed, PG&E acknowledged its intent to apply its retained RECs "toward meeting PG&E's bundled customer RPS obligations."[16] The PD errs in failing to account for these values.

Finally, the PD raises the concern that "valuing all retained or unsold RECs at this time might be perceived as prejudging the ultimate outcome of Working Group Three's proposal on portfolio optimization."[17] Declaring a value of "zero" is just as likely to be prejudicial, only in the other direction.

For all of these reasons, the Commission should reject the PD's adoption here of a zero value for unsold RPS in the benchmark calculation. To the extent that Working Group 3 is taking this issue up, all the more reason to not address it now.

IV. ALL UNSOLD RA ATTRIBUTES SHOULD BE VALUED AT THE PRICE FLOOR, IF ANY, SET BY THE IOU IN ITS SALES PROCESS FOR SUCH ATTRIBUTES TO THE EXTENT THE PRICE FLOOR EXCEEDS THE AMOUNT REQUIRED TO AVOID PENALTIES

In D.18-10-019, the Commission directed the IOUs to assign a "zero or de minimis price" to unsold RA capacity.[18] The Scoping Memo likewise directed parties to identify parameters for a "de minimis" price.[19]

The co-leads were unable to reach agreement on what "*de minimis*" means. CalCCA starts from the standpoint that it must mean *something*, and that to reduce it to a dollar value is best tethered to some objectively established amount. Accordingly, CalCCA proposes to use the sales "price floor" that IOUs set as, essentially, a reserve price below which they will not sell, to set the minimum (and so *de minimis*) as the value of the unsold RA. The Joint IOUs would read *de minimis* out of D.18-10-019, and simply value all unsold RA at zero. The PD erroneously adopts the Joint IOUs' approach.

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15 Comments of *California Community Choice Association on WNR Group One Draft End to End Benchmark and True-Up Proposal*, (CalCCA Comments) at 6.

16 PG&E Response to Join-CCA_004-QB, attached as Appendix B.

17 PD at 35.

18 D.18-10-019, Ordering Paragraph 1.c. at 159-160.

19 Scoping Memo, Issue 7, at 4.

The PD states that *de minimis* means close to zero, [20] and CalCCA agrees that *de minimis* means a small amount. That said, there must also be some rationale or "parameter" around the purpose of the value. For this reason, CalCCA proposed to rely on any value established by the IOU as a price floor in the sale of RA attributes. The price floor is the non-zero price at which the IOU deems it more reasonable not to sell the attribute than to sell it. Consequently, as CalCCA observed in its comments on the Working Group 1 Report, "[t]he use of a price floor implicitly acknowledges a value for the attribute." [21] As the PD notes, CalCCA's view was supported by the Alliance for Retail Energy Marketing, the Direct Access Customer Coalition, and the City of San Diego.

The PD concludes that to use the price floor would "provide a disincentive for the use of a price floor in an IOU solicitation,"[22] basing the analysis on the need to avoid Resource Adequacy Incentive Mechanism (RAAIM) charges. Even if the Commission agrees with the PD's assessment on RAAIM penalties, that does not mean that all price floors should be disregarded. To the extent that the IOU chooses a price floor that goes beyond mere penalty avoidance, its reasoning must be that retention has value above and beyond the value of any proposed sale.

For these reasons, CalCCA proposes that, at a minimum, the Commission direct that any price floor set above the level required for RAAIM penalty avoidance will be deemed the *de minimis* value of the attribute. Any other approach could allow the IOU to set unreasonable floor prices, allowing a cost shift from bundled to departing load customers by reducing the RA benchmark.

V. THE COMMISSION SHOULD DIRECT IOUS TO SELL EXCESS BY THE END OF AUGUST PRIOR TO THE DELIVERY YEAR

In addition to disagreeing over the appropriate price for unsold RAs, as discussed in Section IV, the co-leads differ on the conditions under which RA capacity may be deemed "unsold" and valued at a zero or *de minimis* price. The PD's resolution of this difference unreasonably gives bundled customers first call on the IOU's RA capacity and fails to appreciate the signals it would send to IOUs, who hold the lion's share of RA capacity in the market.

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20 PD at 40.
21 CalCCA Comments at 5.
22 PD at 42.

Moreover, the PD is internally inconsistent, failing to craft a solution that reflects its justification for adopting the IOUs' position. CalCCA thus requests that the Commission modify the PD to permit RA capacity to be deemed "unsold" and valued at zero or a *de minimis* price in the PCIA calculation only if the IOU has *timely* offered the RA to other LSEs to enable their compliance.

It is important to start with a clear understanding of what is at stake in this debate. The failure to provide requirements regarding the timing of an IOU's RA capacity sales creates a perverse incentive. An IOU has every incentive to hold back RA capacity from the market – from other LSEs whose customers pay for the capacity – as long as possible to mitigate any risk of its potential noncompliance. If all unsold capacity, regardless of when the capacity is offered for sale, is valued at zero or a *de minimis* price, it increases the PCIA charge paid by its competitors' customers. In other words, the IOU has no incentive to timely offer the capacity to the market, further squeezing an already tight RA market. Other LSEs consequently face a triple-whammy: they face higher RA costs in the RA market due to the resultant supply constraint, pay a higher PCIA due to the zero value of unsold amounts, and may incur noncompliance penalties because unsold RA was not offered in time for other LSEs to buy it for compliance purposes. This cannot be the right outcome.

CalCCA proposed in its comments on the Working Group 1 final report that RA capacity be considered "unsold" only if the RA is offered to the market "by the end of August preceding the compliance deadline for the relevant year, but not sold."[23] PG&E, not surprisingly, urged more liberal boundaries for RA capacity sales, contending that any RA offered for sale in a solicitation process — regardless of timing — but not sold should be valued at zero.[24] The PD punts the issue to Working Group 3 but, on an interim basis, sides with PG&E.[25] The PD accepts PG&E's argument that "[b]ecause final RA allocations are not determined until September, having the IOUs sell off RA resources prior to the September date could put bundled customers at financial risk, should the forecast change."[26]

The PD errs in two important respects. First, the PD grants bundled customers "first dibs" on all RA products in the portfolio. It provides that only when the needs of the utility's bundled customers are satisfied should other customers — customers who are bound to pay for

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23 PD at 37.
24 PD at 37.
25 PD at 40-41.
26 *Id.*

the RA capacity — have access. This approach unreasonably discriminates against departing load customers. In protecting bundled customers from financial consequences for shortfalls in their RA procurement, it shifts the financial risk to departing load customers and their suppliers by contributing to a tightening market, encouraging other generators to increase RA prices to CCAs who must buy sufficient RA to meet compliance obligations, and passing unsold RA costs onto CCA customers through PCIA costs. Second, even if the PD's "bundled customers first" philosophy could be rationalized, the PD fails to act on its own observations. The PD implicitly acknowledges that the needs of the bundled IOU customers are known with certainty when the IOU's final RA requirement is received. Yet nothing in the PD requires the IOUs to immediately offer any excess to the market after receiving that requirement.

Pending resolution and without prejudice to the issue and Working Group 3, the Commission should clarify the PD to more fairly balance its impacts on departing load customers. The Commission has a continuum of options before it to do that. In CalCCA's ideal world, IOUs would be required to offer excess RA to the market early in the year, in a Spring solicitation, for that RA to qualify for "*zero or de minimis*" valuation. This approach would properly recognize that all LSEs bear risk as their forecasts and requirements change. Nonetheless, to create an alternative, CalCCA was willing to move the requirement in its proposal to the end of August, to allow for greater IOU certainty. By the end of August, the IOU will have received its initial forecast requirement from the Commission and will have updated load forecasts to account for load migration. Consequently, by the end of August, the IOUs should face little risk of offering RA capacity to the market; indeed their risk at the point should not be any more or less than any other LSE required to balance their position following receipt of final requirements. At the very least, however, the PD's recognition that the utility risk is eliminated once it receives its final allocation compels a requirement that the utilities offer excess RA for sale within five business days following receipt of their final RA requirements. Any resources not offered for sale at that time, which are not ultimately sold, may not be deemed "unsold" resources for benchmark purposes and will be deemed "sold" to bundled customers at the benchmark price.

VI. THE COMMISSION SHOULD MODIFY THE PD TO CONFORM TO THE CO-LEAD'S PROPOSAL REGARDING VALUATION OF RETAINED RA

The PD provides that RA that is "retained for IOU use" will be valued at the applicable benchmark, whether Forecast or Final.[27] While this conclusion mirrors the language presented in Tables 1a and 1b of the WG 1 Report, the PD misses the definition provided by the co-leads for RA "retained for IOU use." Co-leads define this term as "the amount of RA not offered for sale or forecasted to be offered for sale."[28] The Commission should modify the PD to include this critical definition and avoid potential disputes in ERRA proceedings.

VII. THE COMMISSION SHOULD CLARIFY FORECASTING AND TRUE-UP MECHANICS IN ADVANCE OF ERRA FILINGS

The co-leads reached consensus on the general methodology for forecasting unsold RA and for truing up fourth quarter (Q4) forecasts to actuals for the purposes of Energy Resource Recovery Account (ERRA) proceedings. However, although implicit in the Commission's findings, the Proposed Decision does not detail these associated true-up mechanics in two important respects.

First, the PD does not reflect the co-leads' agreement regarding the quantity of unsold RA that may be forecast in a Forecast ERRA proceeding. The co-leads agreed that if the forecasted volume "is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review." Any other result will be subject to review for reasonableness.[29] Expressly adopting this recommendation will bring more discipline to the forecasting of unsold RA and ease the time required in the ERRA proceeding to address this issue.

Second, the Proposed Decision does not specify how a "true up" of forecast Q4 Portfolio Allocation Balancing Account (PABA) balances to actuals will be accomplished. When the true up for year n to the prior year's forecast occurs in Q4 of year n, final PABA balances will not be

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[27] PD, Appendix B, at 2.

[28] WG 1 Report, Table 1a, note 1 at 7.

[29] Pacific Gas and Electric Company (U 39-E) and California Community Choice Association Working Group One Report on Brown Power, RPS and RA True-Up (Issues 1 Through 7), May 31, 2019, at 8-9.

available. The true-up and any forecast ERRA value will thus be based on a forecast of year n Q4 costs and revenues. Consequently, the Q4 estimate used in the true up must itself be subject to true-up in year n+1 for accuracy. The Commission should amend the Proposed Decision to make this assumption explicit. Specifically:

> Forecasted Q4 costs and revenues for a particular year (n) used in the true-up for that year should be trued-up to actual Q4 costs in year n+1, with those updated costs reflected in the ERRA forecast for year n+2.

Proposed findings and conclusions are provided in Appendix A.

VIII. CONCLUSION

For the reasons specified above, CalCCA respectfully requests that the Commission adopt the changes to the Proposed Decision specified herein.

Respectfully submitted,

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APPENDIX A

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs

Findings of Fact:

6. ~~Incorporating fixed~~ Fixed-price bundled transactions should be included in~~to~~ RPS Adder calculations to the extent feasible and provided that incorporating these values does not materially sacrifice the accuracy of the benchmark.~~is expected to produce more accurate results and is ultimately the proper approach.~~

7. Information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2) will help Staff monitor the impact of fixed-price transactions on the RPS Adder, but relying upon this broad scope of transactions for the benchmark calculation would undermine the objective of reflecting current market values ~~and propose a method to incorporate fixed-price contracts into the RPS Adder calculations~~.

19. Unsold RPS products ~~also may well have no value if they expire or are banked by an LSE that is not able to use them for compliance~~ have immediate value to the IOU and its bundled customers by insuring against noncompliance and providing greater carbon-free energy for purposes of the Clean Net Short and the Power Content Label.

21. ~~RECs have value to the IOUs when they use the RECs. It is not clear under what circumstances costs may~~ Because unsold RPS products create immediate value for the utility and its bundled customers, failing to include those products at the RPS benchmark shifts costs from ~~between~~ bundled ~~and~~ to unbundled customers ~~when IOUs hold, do not sell, and do not use RECs~~.

~~22. If the IOUs use RECs in the future based on approved procurement plans,~~

~~the value in the year of generation may be different from the value at the time of the future transaction. To value all RECs in the year of generation could conflict with Commission-approved plans.~~

23. Failing to value unsold RECs in the PCIA benchmark calculation would prejudice the outcome of Working Group 3.~~Valuing all retained/unsold RECs might be seen to presuppose or conflict with the ultimate outcome on portfolio optimization, and possibly render that result moot as to the unused RECs that already have been valued and included in a PCIA calculation~~.

26. The co-chairs focused on zero and the floor price, and CalCCA identified as the parameter for determining a de minimis price the implicit value of the RA product revealed in any increment of the price floor above any amount required to avoid penalties. ~~but not on the parameters that will help define a de minimis price.~~

~~27. There are compelling arguments for why the floor price should not be designated as the "de minimis" price.~~

~~29. If the Commission were to assign the RA floor price value to unsold RA, this might imply that it is preferable for IOUs to sell their RA below the floor price and incur the penalties.~~

NEW FoF: For purposes of RA capacity valuation, "retained for IOU use" is defined as "the amount of RA not offered for sale or forecasted to be offered for sale."[30]

Conclusions of Law:

4. Energy Division should monitor the impact of fixed-price transactions and propose a method to include fixed-price contracts in calculating the RPS Adder by the end of 2020, to the extent such a method is feasible and does not undermine the accuracy of the benchmark. The

[30] WG 1 Report, Table 1a, note 1 at 7.

Energy Division Director shall ~~should be authorized to~~ hold workshops or utilize the existing Working Group process to develop the proposal.

20. ~~The value of unsold~~ Unsold RPS resources should be valued at the RPS benchmark. ~~zero.~~

22. The price for unsold RA should be set at the price floor set by the IOU in its sales of excess RA products, to the extent such floor exceeds the amount required to mitigate RAAIM penalties. ~~Because the floor price set in a solicitation is not necessarily a de minimis price and no party provided compelling arguments to set the floor price as the "de minimis" value for the unsold RA products, the Commission should adopt PG&E's proposal to set a zero value for unsold RA resources.~~

Ordering Paragraphs:

3.b. The value of unsold RPS products shall be ~~zero.~~set at the RPS benchmark.

3.e. ~~The value of unsold RA products shall be zero.~~ The price for unsold RA should be set at the price floor set by the IOU in its sales of excess RA products, to the extent such floor exceeds the amount required to mitigate RAAIM penalties.

New OP: The IOUs shall offer all excess RA capacity to the market not later than the end of August prior to the compliance deadline.

NEW OP: The IOU can forecast any volume of unsold RA. If the forecasted volume is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review. The calculation of the amount corresponding to the change in departing load is the product of the year-over-year difference in IOU load share and the system RA requirement for each month. Volumes outside of range may be subject to reasonableness review in the ERRA Forecast proceeding.

NEW OP: Forecasted Q4 costs and revenues for a particular year (n) used in the true-up for that year should be trued-up to actual Q4 costs in year n+1, with those updated costs reflected in the ERRA forecast for year n+2.

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APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2020 Forecast
Application 19-06-001
Data Response

PG&E Data Request No.:	Joint-CCA_004-Q13		
PG&E File Name:	ERRA-2020-PGE-Forecast_DR_Joint-CCA_004-Q13		
Request Date:	August 13, 2019	Requester DR No.:	004
Date Sent:	August 27, 2019	Requesting Party:	East Bay Community Energy/Marin Clean Energy/Peninsula Clean Energy/Pioneer Community Energy/San Jose Clean Energy/Silicon Valley Clean Energy/Sonoma Clean Power/Valley Clean Energy Alliance
PG&E Witness:	Marcus Keller	Requester:	Tim Lindl

QUESTION 13

Referring to the Chapters 9 Confidential Workpapers:

(a) Are all of the RECs in the WREGIS used by bundled customers to comply with the PG&E's RPS obligations?

(b) Are any of those RECs allocated to other LSEs in any manner other than direct sales?

ANSWER 13

PG&E objects to this question as it is not relevant to this proceeding and should be raised in either the RPS Plan or RPS Compliance proceedings. With that, please see the following responses.

a) RECs that are ultimately retained in PG&E's WREGIS account are expected to be used towards meeting PG&E's bundled customer RPS obligations.

b) Outside of RPS sales, RECs have not been allocated to other LSEs.