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)**

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S PROPOSED DECISION

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Pursuant to Rule 14.3 of the California Public Utilities Commission (CPUC) Rules of Practice and Procedure, the California Community Choice Association (CalCCA) submits these comments on the proposed decision of Administrative Law Judge (ALJ) Roscow (PD).

I. INTRODUCTION AND SUMMARY

The Proposed Decision reflects careful legal analysis, an impressive synthesis of a large, data-intensive record and the intent to reasonably balance the interests of bundled and departing load customers in equitably allocating Power Charge Indifference Adjustment (PCIA)-eligible costs. Several aspects of the PD contribute significantly to its balance. First, the PD is faithful to the Legislature's directives regarding the scope of PCIA-eligible resources. Second, it recognizes the transitional and longer term dimensions of the problem, maintaining the existing methodology during the transition to a voluntary, market-based long-term solution. Third, it recognizes, through the adoption of a cap and collar on the PCIA, the potential destabilizing effect of the significant changes it proposes to the existing PCIA benchmark.

Despite these strengths, CalCCA recommends limited modification and refinements of the PD. The final decision should:

- ✓ Abandon the PD's proposed "true up" process because it is insufficiently developed and not be ready for implementation.

- ✓ In the absence of abandoning it, clarify that the annual "true up" will true-up costs, revenues and load, but will not adjust the forecast estimate of portfolio value. This approach (1) achieves the goal of precision where precision can be attained; (2) recognizes the inherent uncertainties and complexities in valuing the "value of benefits that remain with bundled service customers," and (3) reduces the disruption in predictability, certainty and stability of the PCIA caused by the annual true-up.

- ✓ Reject the PD's "bottom of the barrel" capacity valuation, replacing it with a product-specific, weighted-average benchmark that more reasonably reflects the real-world stratification of capacity value.

CalCCA also recommends providing a clearer road map for the long-term, voluntary, market-based solution that will be explored in a new phase of this proceeding. In particular, this should leave open the possibility for redistribution of more than just the "excess" in the utilities' portfolios and should state a policy preference for the development of verifiable long-term valuation benchmarks for calculating and allocating PCIA-eligible costs.

II. THE TRUE-UP MECHANISM ADDS INSTABILITY TO THE PCIA AND SHOULD BE ABANDONED OR ALTERNATIVELY SHOULD BE REFINED.

The PD concludes that "[a] true-up mechanism should be adopted to ensure that bundled and departing load customers pay equally for PCIA-eligible resources."[1] The PD errs in four respects. First, the PD fails to provide sufficient detail to understand the nature of the true-up it recommends. Second, the true-up does not square with Guiding Principle 1.b., which requires that any solution "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[2] Third, any assumption that the "value of any benefits that remain with bundled service customers" can be determined with a level of precision that warrants a true-up is erroneous. Fourth, certain portfolio costs, particularly associated with RA capacity, are set in base rates in general rate cases and are not updated for bundled customers. Therefore, there is no basis for updating RA costs and values for departed customers.

A. Calculating PCIA-Eligible Costs

The limits of a PCIA true-up can best be understood by examining the process for determining and allocating PCIA costs. PCIA-eligible costs are equal to net portfolio costs – costs less revenues -- reduced by the value of the portfolio remaining to serve bundled customers.[3]

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1 Proposed Decision, Conclusion of Law 16, at 126.

2 Scoping Memo at 14.

3 Net costs must be reduced by the "value of the any benefits remaining with bundled service customers." Cal. Pub. Util. Code §366.2(g).

The first step, determining net portfolio costs, can be done precisely. The costs of the utility portfolio are actually known in hindsight through CAISO settlement and bilateral sales revenues, along with the relative proportion of bundled and departing load customers.

Unlike these elements of the calculation, valuation of capacity, RPS and other attributes that remain in the utility portfolio to serve bundled customers necessarily requires estimation – proxies -- since these products are not transacted in the market. In other words, truing up an estimate, using values that are not necessarily representative of the value of remaining portfolio attributes, as discussed in Section II.D, is just substituting one estimate with another and will not add to precision.

B. The PD's Recommended True-Up Lacks Clarity.

While the PD recommends a true-up, it fails to specify what elements of the PCIA calculation will be subject to the true-up. The PD simply references a utility exhibit (Exhibit IOU-1)[4] that was based on the adoption of PAM/GAM, which only provided "general concepts" and has no relevance to the overall framework proposed by the PD. Without greater analysis and definition, the true-up as proposed cannot be implemented.

The calculation presented in Exhibit IOU-1 does not explain how a true-up would be applied in the PD's PCIA benchmark framework. The PD does not explain how that calculation, based on the GAM/PMM, could be applied to the PCIA benchmark framework. One conclusion that can be drawn, however, is that the true-up was intended to focus on only the elements of the PCIA for which there are actual transaction values: costs and revenues. The Joint Utilities state that "[w]hile the initial rates for both the PMM and GAM portions of the portfolio will be set in the Joint Utilities' respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings based on a forecast of costs and offsetting market revenues (forecast net resource costs), those rates will be trued-up annually based on actual portfolio performance and realized

4 *See* Exh. IOU-1 at 1-21.

market revenues (actual net resource costs), **as well as billed revenues (i.e., sales) received from customers**.[5] TURN's position similarly focuses on actual market revenues:

> "At the end of the year, the net costs of the PCIA resources should be calculated based on the recorded gross costs of the resources **minus the revenues such resources earn in relevant markets**. These markets would include sales into the energy and ancillary services markets operated by the CAISO along with revenues from forward sales of energy, renewable energy and RA capacity to other market participants."[6]

The gist of the discussion suggests a true up of costs and revenues actually realized or transacted.

If, instead, the PD intended to true-up the forecast cost of the untransacted portfolio remaining to serve bundled customers, it fails to explain the mechanics or the benefits of this approach. Bundled sales under the utility generation tariff rates are the only transactions that exist where resources used to serve bundled load actually generate "billed revenues (i.e., sales) received from customers"[7] or "the revenues such resources earn in relevant markets."[8] Accordingly, using the criteria proposed by TURN and the Joint Utilities, the only "revenues" available to true up costs would be the revenues the utility receives for the sale of the products to bundled customers.[9] There is no other transacted or realized value, and using anything other than the sale to bundled customers would effectively invent a non-existent transaction that was never made (sales of the bundled supplies assumed to be made at the prices earned from transactions in which the non-bundled supply is sold). Moreover, it is not clear what the benefit would be of truing up one portfolio value estimate to another estimate – particularly if both are based on referents that do not reasonably represent the value of the remaining portfolio products.

ORA's proposal, which the PD also cites, appears to offer more clarity. As the PD explains, ORA's true-up would be "based on actual portfolio performance and

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5 Exh. IOU-1 at 1-22:29-23:3.

6 Proposed Decision at 79 (quoting TURN Opening Brief at 16).

7 Exh. IOU-1 at 23:23.

8 Exh. TURN-1 at 8:22-23.

9 Here we are referring to the fully-allocated cost of service rate for generation service charged to bundled load customers, not the much smaller synthetic rate components identified in the Joint Utilities' testimony (e.g., the balancing accounts and subaccounts such as PABA, PMM, GAM, CTC, etc.).

market settlement data," which could be "'audited and verified in the IOUs' ERRA Compliance applications.'"[10] The most reasonable interpretation of this proposal is that actual costs and actual revenues will be subject to true-up – not the portfolio estimate.[11]

Any true-up, as discussed below, will undermine predictability, stability and uncertainty for departing load customers and their LSEs. The Commission should reject any true-up or, at a minimum, any true-up should be clarified and limited to a true up of actual load, costs and revenues as proposed in Section E.

C. A True-Up Does Not Comport With Guiding Principle 1.b.

Guiding Principle 1.b. adopted in the Scoping Memo requires that any solution "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[12] A true-up lacks predictability and does not promote certainty and stability. On these grounds, a true-up should be rejected.

Today, a CCA knows its PCIA responsibility before going into a year and making additional procurement decisions. The PCIA is forecast in the Forecast ERRA, without subsequent true-up. This approach allows the CCA certainty in managing its portfolio. The PD, however, would upset this balance. A CCA would be required not only to the risk of its own procurement decisions – a risk all LSEs must manage – but the risk of PCIA variations resulting from the utility's portfolio management. While the utility will be fully aware of changes in portfolio costs or values throughout the year and can take that knowledge into account in its procurement decisions, the CCA will have no visibility into those decisions or the potential effects on the PCIA. Critically, recognizing the different positions of utility and non-utility LSEs in this respect requires efforts to mitigate the risk of PCIA fluctuation for non-utility LSEs. A true-up does not manage this risk, it exacerbates the risk.

The true-up thus fails to provide predictability, certainty and stability, as required by Guiding Principle 1.b., and should be modified as proposed in Section D below.

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10 Proposed Decision at 79 (quoting ORA Opening Brief at 141).

11 Even ORA's proposal requires additional clarification, as do TURN's and the IOU's true up proposals, that **all** generation revenues, including from sales of ancillary services and other operating revenues, be included and netted against portfolio costs.

12 Scoping Memo at 14.

D. A True-Up of the "Value of Benefits Remaining With Bundled Customers" Would Be Illusory.

A true-up of load, costs and revenues could achieve a greater degree of precision in outcome, but would come at a cost to predictability, certainty and stability. The suggestion that greater precision can be achieved by truing up the value of portfolio benefits remaining with bundled customers – benefits that are not measured by actual transactions -- is highly misleading.

The benchmarks used to value the unsold utility portfolio, whether in the existing or PD methodology, will always be but proxies for the value of the remaining products and attributes. The actual "receipts" received for the sale of the utility's *excess* RA capacity, for example, may bear little or no relationship to the value of the long-term capacity benefits remaining within the portfolio to be used by bundled customers.[13] Attributes remaining in the portfolio, for example, provide a "buffer" for failing to meet statutory or Commission-established requirements,[14] and mitigate price risk[15] - value not transferred to the buyer in the short-term transactions.

The problems with buying into the Joint Utilities' "precision" arguments are discussed more extensively in CalCCAs' Reply Brief.[16] Portfolio valuation – valuation of products that are not transacted in the market – is not an exercise conducive to precision, as the Legislature recognized. Consequently, even ignoring the failure of the true-up to provide predictability, stability and certainty, a true-up of *all* elements of the PCIA calculation is unreasonable and contrary to statute.

E. Any True-Up Must Be Clarified and Limited to Actual, Measurable Values.

While CalCCA continues to oppose a true-up due to concerns over rate predictability and stability, if a true-up is adopted, the final decision should clarify its scope and mechanics. At most, it should allow a true-up of load, actual generation costs and actual market revenues for product sales – all values that can be actually measured and for which "receipts" actually exist. A true-up should not, however, provide a true-up of the forecast value of portfolio products and attributes that are not transacted in the market, unless it incorporates the revenue from bundled load sales at full utility generation tariff rates, as described above. A methodology that permits a true-up of the volume of RA and RPS attributes remaining in the utility portfolio using only

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13 The problem is further described in Section IV.

14 *See, e.g.,* Exh CalCCA-102-C at 2-4; *see also* 1 Tr.-C 180-184.

15 5 Tr. 900:8-16 (Hoekstra).

16 CalCCA Reply Brief at 19-20.

short-term market value measures, would ignore Public Utilities Code §366.2(f)(2) and create volatility *without* gaining precision.

Regardless of its formulation, any true-up will create added volatility and risk for non-utility LSEs to manage. Consequently, adequately collaring the PCIA annual changes, as discussed in Section V is critical to the success of this approach.

III. THE CAPACITY BENCHMARK SHOULD BE MODIFIED TO MORE REASONABLY REPRESENT THE VALUE OF CAPACITY.

The PD adopts TURN's proposal to reduce the RA capacity benchmark by roughly half. Today, the capacity benchmark is based on the "'going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine'" that is available to serve the grid when required,[17] which yields a value of approximately $58.27 kW-year, or approximately $4.86/kW-month on average. Based *solely* on TURN's comparison of this price to the prices reported in the Energy Division's RA Report and disregarding the extensive evidence in the case regarding long-term benchmarks, the PD recommends that the capacity benchmark be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n)."[18] It also recommends a "zero or de minimis price" for any capacity that remains unsold.[19]

In its choice of capacity benchmark, the PD misses the primary aim of the proceeding, avoiding cost shifts, and exacerbates the existing cost shift from bundled to departing load customers. The PD's use of this capacity value price referent:

- Significantly undervalues the capacity, failing to recognize the "buffer" and hedging value provided by portfolio resources.[20]

- Is directly at odds with the Commission's continued long-term valuation of capacity for other purposes -- distributed energy resources cost-effectiveness evaluations, bundled procurement and rate-setting.[21]

- Implicitly accepts the untenable notion that long-lived power supply resources have long-term planning, hedging and resource diversity value *up until the very moment* they are

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17 Proposed Decision at 37.
18 *Id.* at 76.
19 *Id.*
20 CalCCA Opening Brief at 54-55; *see* CalCCA-102C at 3-4; *see also* 1 Tr.-C:180-184. (Lawlor/PG&E).
21 CalCCA Opening Brief at 54-55.

placed into service; thereafter those same resources only have short-term market value based on prices that can be recovered for the sale of limited Resource Adequacy (RA) volumes transacted in the short-term balancing market. [22]

- Implies that 100 percent of the resources in the utilities' portfolios could be replicated at these short-term prices – a conclusion that is unsupportable, as the Commission pointed out in its May 2017 Padilla Report.[23]

- If applied to utility-owned generation (UOG) operating costs, implies that UOG is being operated uneconomically.[24]

The use of this short-term capacity benchmark is also a signal to Energy Service Providers (ESPs) and Community Choice Aggregators (CCAs) that is counterproductive in the state's goals of decarbonization. It will drive these LSEs to maximize unbundled, short-term products rather than the new long-term resources that support state policies focused on long-term procurement to achieve renewable and reliability objectives.

For these reasons, as discussed in greater detail below, the capacity benchmark, when combined with the PD's proposed true-up, creates a cost shift from bundled customers to departing load customers. Recognizing the PD's efforts to find balance among perspectives, CalCCA proposes modification of the PD's capacity valuation by proportionate blending of the approaches proposed by the parties. While the approach departs from CalCCA's clear view that long-term values should be used to value long-term resources, a blended benchmark will provide a more reasonable approach than proposed by the PD.

A. The PD Errs in Concluding That Only Actual Market Revenues for Short-Term Sales Should Be Used to Estimate Capacity Value.

The PD markedly understates the value of capacity in the Joint Utilities' portfolios. The adopted approach would use a weighted-average value from the Energy Division's annual RA Report, although the PD is unclear about: (1) which value among the many presented in the report would be used, (2) whether and how long-term contracts will be incorporated into the weighted average, (3) how value should be attributed to RA Capacity in contracts whether other

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22 CalCCA Opening Brief at 55.

23 *See* Exh. CalCCA-106 The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (Pursuant to Public Utilities Code Section 913.3), May 1, 2017 (2017 Padilla Report) at 12.

24 CalCCA Opening Brief at 57.

products are bundled with RA, such as energy and ancillary services available in tolling and battery storage contracts, or (4) how the value will be available for review and audit for reasonableness by the parties.

The Joint Utilities cited two numbers from the 2016 RA Report: \$24.24/kW-year[25] and \$37.20/kW-year.[26] It is readily apparent that these values are stale, unrepresentative of the broader market for all RA resources used for compliance, and inapplicable to future capacity valuation, given the extensive evidence in the record regarding diminishing surplus capacity because of retirements and contract expirations, rising capacity values, first-ever invocation of one CPM and RMR contracts for periods of a year or longer, and the planned imposition of a multi-year RA requirement. Extracting the values from the RA Report, regardless of which value, scrapes the "bottom of the barrel" for capacity price proxies, accounts for no more than 20 percent of the RA Capacity used for compliance[27] and does not reasonably represent the value of all of the capacity in the Utilities' PCIA-Eligible portfolios.

The range of values for capacity discussed in the proceeding and more recently made available through a PG&E advice letter demonstrate that capacity value can range from as low as \$24.24/kW-year[28] per kW-month on average for system RA, based on the 2016 RA Report, to \$124/kW-year when considering the weighted average of RA and CAM resources,[29] up to \$172 kW-year for PG&E's recent Moss Landing Battery Storage Project[30] or \$233 kW-year "cost of new entry" approach discussed by AReM/DACC.[31] Simply glancing at the chart below, which shows the wide range of possible capacity values, makes it evident that the PD's capacity value is unreasonable.

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25 Joint Utilities Rebuttal Testimony at Appendix E line 19 (first column), citing the \$2.10/kW-month (which converts to \$24.24/kW-year) average price for 2016-2020 NP-26 RA contracts from Table 7 of the 2016 RA Report.

26 Joint Utilities Opening Testimony at 2-19 and n. 35, citing the \$3.10/kW-month (which converts to \$37.20/kW-year) weighted-average price for all 2016-2020 RA contracts from Table 7 of the 2016 RA Report.

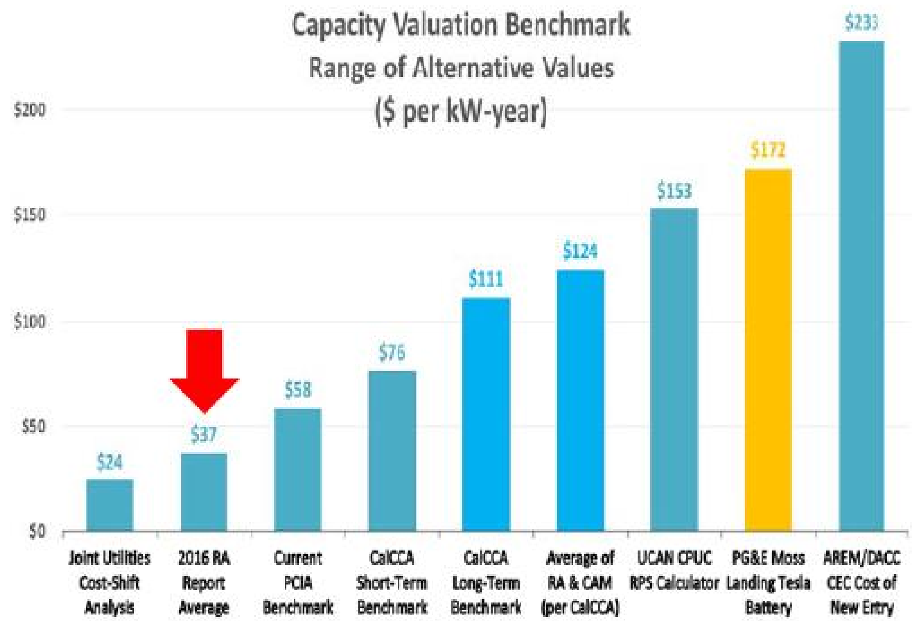
27 CalCCA Rebuttal Testimony at 2B-4. The 20% figure also excludes demand response, CAM, and RMR resources, further reducing the amount of capacity the values in the CPUC's RA Report represent.

28 *Id.* at 41.

29 CalCCA Rebuttal Testimony at 2B-5 and CONFIDENTIAL Exh. CalCCA 2B-A.

30 *See* PG&E Advice Letter 5322-E, June 29, 2018

31 Exh. AREM/DACC 1-1 at 20.



The unreasonableness of this approach is bolstered by the Commission's own observations on the use of short-term prices for valuation. Rejecting the utilities' proposal to use short-term values to value their entire RPS portfolio, the Commission concluded:

> The CPUC's concern with the IOUs' approach is two-fold. 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 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.[32]

In this same vein, the prices realized in short-term sales of excess RA capacity cannot fairly represent the value of the entire portfolio of capacity.

The Joint Utilities' own testimony also demonstrates that it would be unreasonable to rely on short-term prices for the entire portfolio value. 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."[33] In addition, the utilities' operation of

32 Exh. CalCCA-106, 2017 Padilla Report at 12.
33 Exh. IOU-1 at 5-9:21-23.

their own generation demonstrates a higher value, as Mr. Kinosian, on behalf of CalCCA, explained:

> A higher value for capacity from PCIA-eligible resources is revealed through a comparison of those resources' operating costs with the current PCIA benchmark. PG&E continues to operate its fossil facilities (Gateway, Colusa and Humboldt), and its nuclear facility (Diablo Canyon), despite those facilities having avoidable, incremental costs of operation that are significantly above the current combined PCIA benchmark for energy and capacity.[34] *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.[35]

He concluded that the incremental, avoidable cost incurred by PG&E and SCE to provide RA from their fossil and nuclear resources was well above the current RA proxy of $58/kw. Either these plants are uneconomic to continue to operate or, more likely, the existing capacity benchmark – even the higher benchmark under the existing methodology -- understates the value of the resources in the portfolios.[36]

Finally, PG&E has acknowledged the additional value to the capacity held in the portfolio.[37] By retaining excess capacity, the utility essentially has insurance to avoid non-compliance penalties, by retaining a "buffer" of excess RA until compliance is certain. It also avoids the possibility of having to backfill when they experience a shortfall and thus avoid price risk. These and other benefits identified accrue to bundled customers regardless of any sale of short-term capacity.

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[34] Avoidable costs exclude all costs associated with existing sunk costs (depreciation, income taxes and return on rate base), and include only costs of continuing operation (fuel, O&M, A&G, new capital additions).

[35] CalCCA Rebuttal Testimony at 2B-5-6 (emphasis added).

[36] The high ongoing RA costs of UOG resources should be expected as the current RA benchmark is based on the minimum generic incremental cost of providing RA from a utility-owned fossil plant.

[37] *See supra* n. 14.

B. Assigning a "Zero" Value to Any Unsold Capacity in the Utility Portfolio Is Unreasonable.

TURN proposes to assign a "zero" value to capacity remaining in the utility portfolio. It is not clear whether TURN meant this to apply to *all* untransacted capacity or only that capacity determined to be "excess" to bundled customer needs. And, if the latter was intended, TURN provides no criteria for determining what portion of capacity is excess.

TURN's position not only lacks clarity; it is wrong. Even if a product is not sold in the short-run, the underlying resource maintains long-term value (or, if not, the utility should not be retaining the resource in the portfolio).[38] The resource may have been held for use by bundled customers in either the instant or a future period, to avoid non-compliance with RA requirements, to provide a "buffer" for bundled customers or to mitigate price risk. Moreover, if the Joint Utilities continue the practice of maintaining "buffers" to protect bundled customers until the last moment possible for a sale, assigning this excess a zero value very patently shifts costs from bundled customers to departing load customers. In essence, the portfolio product can be used by the bundled customers as insurance and require departing load customers to bear the economic consequences of that use.

Assigning a zero value also presumes that the utility's decisions regarding which products to sell and when to sell them are completely neutral and reasonable. The record in this proceeding, as the PD notes, should make the Commission uncomfortable in this regard.[39] Neither SCE nor PG&E even attempted to sell excess portfolio products on a long-term basis to maximize product value until very recently[40] (in the shadow of this proceeding). And policing their choices on what, when and how to sell "excess" capacity would be a material challenge.

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[38] *See supra* n. 14.

[39] Proposed Decision at 62.

[40] 4 Tr. 806:8-28-808:1-19 (Lawlor/Cushnie).

C. Relying Too Heavily on Market Prices Driven by Utility Sales Risks Benchmark Manipulation.

It is no secret that downward pressure on the PCIA benchmark makes it more difficult for non-utility LSEs to compete with the incumbent utility. The lower the benchmark value, the more costs are shifted to departing load customers. An incentive is thus present for the utilities to sell RA capacity in a manner that minimizes price – *e.g.,* offering only one month at a time, offering the capacity at an inopportune time in the market, or offering the capacity under less than optimal terms and conditions. Selling a limited amount of RA capacity at low prices could pay big dividends, shifting costs to departing load customers, if the limited number of short-term transactions is used to value 100 percent of portfolio capacity. The problem is further heightened to the extent utility transactions dominate the Energy Division's RA Report. The 2016 RA Report relies on 2,241 monthly contract values but does not specify how many of those contract values involve a sale by one of the Joint Utilities.[41]

Establishing a methodology for valuing capacity that relies heavily on short-term utility transactions places the utilities in a position of further depressing competition. For this reason alone, the RA Report is unsuitable as a proxy for all portfolio capacity.[42]

D. Proposed Composite Benchmark

The determination of a reasonable price for capacity is admittedly a challenge. The record makes abundantly clear, however, that choosing the value at the bottom of the barrel is unreasonable. For these reasons, CalCCA proposes, as a compromise, a composite alternative of capacity values as a transitional approach. As the PD contemplates, the composite benchmark should have separate values for system, local and flexible RA (although the PD does not address how to disaggregate these values from reported data).[43] Price referents should then be represented in the benchmark in proportion to the overall proportion of transactions they represent.

> *System RA.* The Energy Division RA Report's "85% of MW at or below" price for System RA would be selected and used in the weighted average System RA price calculation in proportion to the percentage of compliance products represented by the

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[41] *See* Exh. CalCCA-109, 2016 Resource Adequacy Report, at 6.

[42] CalCCA Opening Brief at 24.

[43] For example, most purchases of Local RA also include the system RA attributes and the 2016 CPUC RA Report did not identify prices for Flexible RA.

> reported transactions. For example, if 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" System RA price would be weighted 25% in the system RA capacity benchmark, while the remaining 75% of the System RA capacity would be valued at the short-run "going forward" operating costs of a combustion turbine, as valued by the CEC ("going forward" cost); this value is comparable to (albeit, still lower than) the avoidable cost the bundled customers incur for the provision of RA from UOG fossil resources.
>
> *Local RA.* The Energy Division RA Report's "85% of MW at or below" price for Local RA would be selected and used in the weighted-average Local RA price calculation in proportion to the percentage of compliance products represented by the reported transactions. If, for example, 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" Local RA price would be weighted 25% in the Local RA capacity benchmark, while the remaining 75% of the Local RA capacity would be valued at the weighted average CAISO CPM price.
>
> *Flexible RA.* Because there are no clear, liquid benchmarks or referents for flexible capacity, all flexible capacity should be valued at the existing "going forward" RA benchmark.

CalCCA continues to believe that this approach – which remains a short-term approach pending development and implementation of observable and verifiable long-term valuation benchmark – will undervalue capacity and send the wrong signals to CCAs procuring capacity for their customers. If the PCIA benchmark signals that RA is worth only $24/kW-year, this benchmark should be consistently applied to all future Commission directed procurement activities such as energy efficiency, distributed generation, storage, and demand response programs. Such an approach, however, would clearly not help California achieve its long-term policy goals. Neither will it position CCAs, to be more aggressive in the acquisition of storage and other preferred resources.

IV. PREPAYMENT

The PD recognizes that a primary challenge associated with the PCIA is the volatility combined with lack of transparency. More specifically, it recognizes that the PCIA presents a great deal of financial risk to departed customers, discourages investment in long-term resources, and threatens departed customers with rate shock if their provider is unable to quickly adapt to tariff changes by IOUs. Because of this dynamic, departed load customers from a variety of customer types and business models advocated for, and the Proposed Decision recognized the value in, the ability for departing load customers such as CCAs to prepay their obligations. There is significant value to be gained by a known, one-time prepayment of charges.

The PD correctly concludes that "the solution that best fits the guiding principles articulated in the Scoping Memo is adoption of a prepayment option for departing customers." To implement this change, the PD recommends that (1) departed customers be permitted to pre-pay their PCIA obligations according to the terms proposed by AReM/DACC, and (2) the utilities be required to negotiate in good faith. Agreements concerning such prepayment would then be submitted to the Commission for review and approval via a Tier 3 Advice Letter.

While the PD heads in a positive direction, it is unlikely to succeed as written. The largest counterparty in these negotiations has shown an active unwillingness to consider prepayment - which is *already an option*. As AReM/DACC notes in its testimony, each utility 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.[44] The utilities even acknowledge that prepayment would provide certainty for their bundled customers as well.[45] However, departing load customers have not had any success in working with IOUs to make use of the existing provisions in IOU tariffs to cooperatively and voluntarily bargain in good faith with departing load customers that are actively interested in pre-payment. Without additional, specific *and* enforceable Commission direction, there is no reason to believe the IOUs will change their approach now.

In this proceeding, IOUs have refused to provide a forecast of departed load obligations and have argued against pre-payment even being *considered*. To now expect these same IOUs to develop a forecast and then negotiate in good faith in calculating terms of payment is unrealistic. To be successful, the Proposed Decision should be supplemented with a requirement that the utilities maintain on an ongoing basis a forecast of departed load obligations for each vintage of departed load. The utilities further should be required to offer a prepayment transaction, according to the terms specified by AReM/DACC, calculated using the forecast of obligations. As both IOUs and departed customers have a vested interest in protecting their customers, the Commission should take the opportunity to show leadership and balance the competing

44 Exh. AD-1 at IV.C 27-28.
45 Exh. IOU-3 at 7B-33

considerations in this arena by defining "indifference" in a manner that establishes up front standards that create a level playing field amongst each customer group that the Commission can then enforce where IOUs and entities with departing load are unable to reach agreement after good faith negotiation.

V. LONG-TERM SOLUTIONS

CalCCA appreciates the PD's direction to begin developing a long-term, voluntary market-based solution in a separate phase of this proceeding. Taking this approach will ensure that the Joint Utilities realign their supply with bundled load and optimize the monetization of their portfolios. The auction proposal advanced by CalCCA would also create a more reliable measure of market value that can be used to benchmark any ongoing stranded costs as the portfolios are adjusted. The PD does not go far enough, however, in establishing the scope of the solution, timelines and expectations for the process.

The PD states:

> We also open a second phase of this proceeding to consider the development and implementation of a comprehensive solution to the issue of excess resources in utility portfolios. We expect that solution to be based on a voluntary, market-based redistribution of excess resources in the electric supply portfolios of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.[46]

While a "voluntary, market-based redistribution" responds to several of the proposals offered in the proceeding to address the utilities' growing mismatch of supply and load, it unnecessarily limits the proposal to redistribution of "excess" resources. CalCCA's approach contemplated the sale and auction not just of "excess" resources, but of all RPS resources and GHG-free resources.[47] All LSEs pay the stranded costs for all of the resources in the Joint Utilities' portfolio, not simply the "excess" resources. Moreover, by unburdening the Joint Utilities' portfolio in this way, it frees the utility to reconstitute its portfolio to better meet bundled customers' requirements. Including the utilities among the potential purchasers, the auction process assures a more liquid market that will produce more meaningful and reasonably representative long-term market prices that are observable and verifiable. Finally, if the Commission truly believes that the value of the resources in the current portfolios is

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[46] Proposed Decision at 3.

[47] *See* CalCCA Opening Brief at 113.

approximated by the short-term market prices that will be developed under the PD's proposed benchmark, then it should give no credence to fears that the utilities will face increased costs if they dispose of resources in the auction but then are required to buy them back at market prices.

The Commission should provide more concrete guidance on this issue and others for the Phase 2 process. The guidance should:

- Eliminate the reference to "excess" resources in its Phase 2 directive, allowing exploration of the CalCCA auction alternative or any other alternative that brings to market more than just "excess" portfolio resources.
- Establish four guiding principles: (1) resources should be offered on a long-term basis; (2) utility portfolio resources should be sold to the market participants who most value the resources, thereby optimizing portfolio value; (3) utility portfolio contracts should be sold intact, where permitted under the terms of the existing agreement and where feasible given the size of the resource; and (4) resources that cannot be sold should be repackaged with terms and conditions that mirror the underlying resources, wherever possible.
- Require implementation of a portfolio sale process by January 1, 2020, as proposed by CalCCA.
- Require the implementation of a "reverse auction" in 2019 to explore opportunities for contract buydowns;
- Require the Energy Division to set an initial workshop to commence Phase 2 one month following the issuance of the final decision in this phase.

In a similar vein, the final decision should clarify that any concerns regarding utility portfolio management should be raised in a Forecast ERRA, to enable direction to the utility before imprudent portfolio management occurs.

VI. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission adopt the PD, subject to the modifications contemplated herein. Proposed Findings of Fact and Conclusions of Law are provided in Exhibit A.

Respectfully submitted,

Evelyn Kahl

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EXHIBIT A

PROPOSED MODIFICATIONS

Findings of Fact

4. A revised RA Adder should be ~~that is~~ calculated with separate benchmarks for system, local and flexible RA to the extent feasible. The system RA benchmark should be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions, in proportion to the percentage of total system RA used for compliance represented by such transactions. The remainder of the benchmark should be calculated using the CEC's short-term "going forward" calculation of capacity value. At this point in the development of flexible capacity values, the CEC's short-term "going forward" is the best available estimate of this value. Together, these components of an RA calculation will produce reasonably accurate estimates~~, if a zero or de minimis price is assigned for capacity expected to remain unsold~~.

19. A true-up mechanism will increase the accuracy of the PCIA cost allocation between bundled and departing load customers only where actual costs and revenues from transactions are available. A true-up of the portfolio value of resources remaining to serve bundled customers will not increase accuracy because there are no actual transactions through which to obtain an "accurate" value. The true-up thus should true up generation and purchase power costs, energy costs and any associated sale revenues. ~~ensure that bundled and departing load customers pay equally for PCIA-eligible resources.~~

~~20. The ratemaking proposal in Exhibit IOU-1 provides general concepts that can be used to implement an annual true-up process for the PCIA.~~

26. An option to prepay would provide simplicity and predictability for departing load customers, and greater certainty in the prepayment rights and obligations would benefit departing load customers.

28. A new phase of this proceeding would enable parties to continue working together to develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

Conclusions of Law

4. The methodology for calculating the RA Adder adopted in D.06-07-030 and modified in D.07-01-030 should be changed to the method provided in Finding of Fact 4. ~~Appendix 1 of this decision.~~

16. A true-up mechanism consistent with Finding of Fact 19 should be adopted to ensure greater accuracy in PCIA cost allocation between ~~that~~ bundled and departing load customers ~~pay equally for PCIA-eligible resources~~.

19. A PCIA collar ~~with a floor and a cap~~ should be adopted to limit the change of the PCIA from one year to the next.

NEW. The IOUs should be required to maintain on an ongoing basis a forecast of departing load obligations for each PCIA vintage, which should serve as the basis for a default prepayment right that can be elected by departed customers.

25. A second phase of this proceeding should be opened in order to consider proposals for a "working group" process to enable parties to continue working together to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

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