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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

DECISION REFINING THE METHOD TO DEVELOP AND TRUE UP MARKET PRICE BENCHMARKS

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DECISION REFINING THE METHOD TO DEVELOP AND TRUE UP MARKET PRICE BENCHMARKS

Summary

This decision refines the method, data, and process requirements for the forecast and true up of the Market Price Benchmarks to be used in determining the Power Charge Indifference Adjustment rate.

This proceeding remains open to address the remaining issues identified in the February 1, 2019 Phase 2 Scoping Memo and Ruling of Assigned Commissioner.

1. Procedural Background

The Power Charge Indifference Adjustment (PCIA) is a mechanism adopted by the Commission as part of a ratemaking methodology developed to ensure that when electric customers of an investor-owned utility (IOU) depart from IOU service and receive their electricity from a non-IOU provider, those customers remain responsible for costs previously incurred on their behalf by the IOUs. The Commission initiated the Order Instituting Rulemaking (R.) 17-06-026 on June 26, 2017 to review the PCIA methodology, which was originally established shortly after the 2001 California energy crisis.

Track 1 of R.17-06-026 examined issues regarding exemptions from the PCIA for the IOUs' California Alternate Rates for Energy (CARE) and Medical Baseline customers. The Commission resolved these issues in Decision (D.) 18-07-009 and D.18-09-013. Track 2 examined the then-current PCIA methodology and considered alternatives to that mechanism. The Commission resolved those issues in D.18-10-019, thus concluding Phase 1. D.18-10-019 also determined that a second phase of this proceeding would be opened in order to establish a working group process to enable parties to further develop proposals for future consideration by the Commission.[1]

On December 19, 2018, a prehearing conference was held to discuss the scope and schedule of Phase 2. Subsequently, the February 1, 2019 Scoping Memo and Ruling of Assigned Commissioner (Scoping Memo) set forth the scope and schedule of the proceeding. The Scoping Memo also established a working group process in the proceeding whereby resolution of the issues of the proceeding would be proposed by three working groups, Working Groups One through Three.

The Scoping Memo identified three sets of issues within the scope of Phase 2 of this proceeding: 1) Issues with the highest priority: Benchmark True Up and Other Benchmarking Issues; 2) Issues to be resolved in early 2020: Prepayment; and 3) Issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction. The first set of issues, issues 1 through 7, concern methodologies to calculate and true up the PCIA Market Price Benchmarks (MPBs) and should be resolved in time to be implemented in the IOUs' respective 2020 Energy Resource Recovery Account (ERRA) Forecast update filings[2] in early November 2019. This first set of issues is the subject of this decision. The September 2019 ALJ Ruling also added issue 11 to the first set of issues to be addressed in this decision, so that the resolution of this issue can

[1] D.18-10-019 at 117.

[2] ERRA proceedings are used to determine fuel and purchased power costs which can be recovered in rates. Annual ERRA Forecast proceeding adopts a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the coming year; whereas annual ERRA Compliance proceeding reviews the utility's compliance in the preceding year regarding energy resource contract administration, administration of utility-owned generation, least-cost dispatch, fuel procurement, and the ERRA balancing account.

be timely incorporated into the IOUs' respective 2020 ERRA Forecast update filings in early November 2019.

The Scoping Memo designated Pacific Gas and Electric Company (PG&E) and California Community Choice Association[3] (CalCCA) as co-chairs of Working Group One and listed the tasks the co-chairs are responsible for. Pursuant to the schedule set forth by the Scoping Memo, Working Group One started meeting in March 2019. The co-chairs of Working Group One served progress reports on March 20, 2019 and April 22, 2019. The co-chairs filed and served the final report, *Working Group One Report on Brown Power, RPS and RA True-Up (Issues 1 through 7)* (May Report) on May 31, 2019. The May Report includes the Working Group One proposal as well as a proposal by The Utility Reform Network (TURN) and informal comments from the parties on the Working Group One proposal and TURN's proposal.[4] The comments attached to the May Report were served by the Protect Our Communities Foundation (POC), Public Advocates Office, TURN, The Utility Consumers' Action Network (UCAN), California Large Energy Consumers Association (CLECA), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Alliance for Retail Energy Markets and the Direct Access Customer Coalition

[3] California Community Choice Association represents the interests of 18 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, 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.

[4] The issue of attaching to the final report comments served by the parties, as opposed to filing comments on the final report, was discussed at the prehearing conference held on December 19, 2018 and parties present at the prehearing conference did not object to it. (*See* Reporter's Transcript at 173.)

(AReM/DACC), the City of San Diego, CalCCA, and jointly by PG&E, SCE, and SDG&E (collectively, the IOUs).

On July 1, 2019, the co-chairs of Working Group One filed and served Working Group One Report on Issues 8 through 12 (July Report). The July Report includes the Joint IOU proposal on billing determinants. The July Report states that the following parties provided informal comments on this issue: The City of San Diego, AReM/DACC, CLECA, CalCCA, Joint IOUs, POC, and UCAN. In addition, CLECA, Joint IOUs, and POC addressed the billing determinant issue in their comments and reply comments filed on July 19, 2019, and July 26, 2019, respectively.[5]

This decision resolves Scoping Memo Issues 1 through 7 and Issue 11 assigned to Working Group One. R.17-06-026 remains open to address the remaining issues assigned to Working Groups One, Two, and Three.

2. Plan of this Decision

This decision is the first in a planned series of decisions in R. 17-06-026. This decision considers working group proposals to refine the method to calculate the MPBs and resolves issues related to PCIA forecast and true up issues, as well as billing determinants. Other topics listed in the Scoping Ruling will be the subject of later decisions.

The determinations we make today will be in accordance with the statutory framework, the overall goal of the proceeding, and the final guiding principles articulated in D.18-10-019. However, to ensure accuracy of the calculations and to account for recent Commission determinations on resource

[5] The *July 9, 2019 ALJ Ruling Modifying Proceeding Schedule* allowed for additional comments and reply comments on the July Report.

adequacy (RA) compliance requirements, the data requirements we adopt today will supersede the data requirements adopted in D.18-10-019. A comparison table of the data requirements adopted in D.18-10-019 and the modifications to those data requirements made in this decision is provided in Attachment A.

For clarity, we will use the following naming conventions and definitions in this decision, except when referring to other documents where other naming conventions may have been used.

- Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year. Market Value consists of three principle components: Energy Value, Renewables Portfolio Standard (RPS) Value, and RA Value. These components are defined below.

  - Energy Value is the estimated financial value, measured in dollars, that is attributed to the energy component of a utility portfolio for a given year.

  - RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year.

  - RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.

- Market Price Benchmarks are estimates of the value per unit (not total portfolio value) associated with three principal sources of value in utility portfolios (energy, resource adequacy, and renewable energy). Each Market Price Benchmark must be multiplied by the relevant portfolio volume as part of the overall calculation of Market Value.

- Energy Index is the Market Price Benchmark that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). Sometimes referred to as "Brown Power Index", "Brown Power component", "Brown Power Adder", or "Brown Power benchmark."

- RPS Adder is the Market Price Benchmark that reflects the estimated incremental value of each unit of RPS-eligible energy[6] that is attributable to the fact of that eligibility, in $/MWh.

- RA Adder is the Market Price Benchmark that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-year). The RA Adder has three subcomponents, reflecting each type of RA product required for compliance with the RA program: system, local and flexible.

3. Issues Before the Commission

Below are the eight issues assigned to Working Group One in the Scoping Memo and addressed in the May Report or July Report. The numbering below corresponds to the issues as listed in the Scoping Memo.

1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true up annually the Brown Power component, the RA Adder and the RPS Adder of the Market Price Benchmark?
2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true up? If so, what are those data/reporting requirements and how should they be considered by the Commission?

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[6] RPS-eligible energy represents the resources in a utility portfolio that qualify to satisfy the utility's RPS obligations.

3. Should the true up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true up process be addressed?
4. Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA Adder and the RPS Adder of the Market Price Benchmark?
5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS Adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?
6. How should the Commission clarify/define forecasting amounts of unsold RA?
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?

11. Should the Commission clarify the definition of billing determinants and their proper usage for calculating the PCIA, and if so, how?

We will address the Scoping Memo issues in a nonconsecutive order. First, we will resolve forecasting related issues (Scoping Memo Issues 4 and 5); and then discuss true up related issues (Scoping Memo Issues 1, 2, 3); and conclude by addressing the value of unsold resource adequacy resources (Scoping Memo Issues 6 and 7) and billing determinants (Scoping Memo Issue 11).

4. Summary of Working Group One Proposal on Issues 1 through 7

In this section, first, we briefly summarize the implementation-related directives provided by D.18-10-019. Second, we describe the Working Group One Proposal on Issues 1 through 7.

4.1. PCIA Calculation Revised by D.18-10-019

Historically, the RA and RPS components of the PCIA calculation only reflected forecasted values, which flowed through each IOU's annual ERRA Forecast Application. In D.18-10-019 the Commission maintained the existing PCIA method, but it revised the Market Price Benchmarks used in the PCIA calculations. The Commission also adopted a true up process to adjust RA and RPS forecasted values based on actual realized market revenues, and directed each IOU to open a Portfolio Allocation Balancing Account (PABA) to begin tracking PCIA net revenues. With respect to the MPBs, D.18-10-019 determined the following:

1. The methodology for calculating the Energy Index will remain the same.
2. TURN's approach for estimating the RPS Adder is adopted. Accordingly, the RPS Adder will be calculated using the reported prices of purchases and sales of renewable energy by the IOUs, Community Choice Aggregators (CCAs), and electric service providers (ESPs) during the two year prior to the forecast year (n-2) for delivery in the forecast year n.
3. TURN's proposal for estimating the RA Adder is adopted. Accordingly, the RA Adder will be calculated using the reported prices of purchases and sales prices of IOU, CCA, and ESP transactions made during year (n-1) for delivery in year n.
4. The RA Adder will be changed to reflect the three types of RA capacity: system, local, and flexible.
5. A true up process for the Adders is adopted.

The data requirements to calculate the forecasted and final Adders, as determined by D.18-10-019, are listed in Attachment A.

4.2. Working Group One Proposal

The May Report presents a proposal refining the method to develop and true up the Energy Index, RA Adder and RPS Adder within the framework established by D.18-10-019. The proposal is briefly described as follows:

The IOUs forecast a PCIA total portfolio indifference amount, which is used to set vintaged PCIA rates for the following year (year n). The forecasted total portfolio indifference amount is equal to the forecasted total cost of the PCIA total portfolio less the forecasted Market Value of the PCIA portfolio attributes (Forecast Market Value). The forecasted total portfolio indifference amount is calculated on a vintaged basis. That is, it is calculated for each year based on resources' contract execution date for contracts and construction start date for utility-owned generation.[7]

The PCIA portfolio attributes included in the PCIA calculation are the energy, RPS, and RA attributes of the PCIA-eligible resources that reflect how those resources are expected to be used in the following year. The approach to calculating the value of these attributes in the forecast depends on whether the attribute is forecasted to be retained by the IOU (Forecast Retained), has already been sold by the IOU (Actual Sold), is forecasted to be sold by the IOU (Forecast Sold), or is forecasted to remain unsold by the IOU (Forecast Unsold).

Actual costs and actual revenues for energy, RA, and RPS resources are recorded to the PABA in vintaged subaccounts. Similar to the forecasted values, the approach to calculating the values recorded to PABA depends on whether the attribute is retained by the IOU (Actual Retained), sold by the IOU (Actual Sold), or is considered unsold (Actual Unsold).

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[7] D.08-09-012 at Conclusion of Law 15.

The year-end overcollections or undercollections in the PABA subaccounts for year n are included in the vintage PCIA rate calculation for year (n+1) as part of each utility's ERRA Forecast Application.

Working Group One's proposed approach to calculating the three MPBs used in the total portfolio indifference amount forecast and true up is shown in Table I.

Table I: Market Price Benchmarks Used in PCIA Forecast and True Up

Energy Index	Separate value for each IOU based on Platts average peak and off-peak market indices for NP 15 and SP 15
RA Adder	• *System* RA (Single value for all IOUs based on transacted RA not used for local or flexible RA purposes) • *Local* RA (Separate value for each IOU Transmission Access Charge (TAC) area based on transacted RA to fulfill local RA requirements) • *Flexible* RA (Single value for all IOUs calculated using transacted flexible RA not used for local RA requirements)
RPS Adder	Single value for all IOUs based on index-plus Portfolio Content Category (PCC)-1 RPS energy transactions

According to the proposal, the Commission's Energy Division Staff (Staff) calculates these MPBs annually for both the forecast and the true up process based on responses to quarterly data requests sent to all load serving entities (LSEs). Staff makes the calculated values available to interested parties at the beginning of November each year; and the IOUs use these values to calculate the PCIA that takes effect January 1 of the following year.

5. Discussion and Analysis

For each of the eight issues listed in Section 3, this decision states the resolution to the issue, describes the proposal, briefly summarizes party comments attached to the reports, and then explains how the Commission determines the issue.

5.1. Developing Forecast Values for Adders (Scoping Memo Issue 4)

Scoping Memo Issue 4 asks which mechanism(s), procedural and/or methodological, the Commission should adopt to develop annually the RA Adder and the RPS Adder. We conclude the following:

Working Group One's proposal on calculating the forecast market value based on the Energy Index, RPS Adder, and RA Adder for system and flexible RA, is reasonable and adopted.

- With respect to the RPS Adder, we also adopt TURN's proposal that all LSEs be required to provide Staff with information on all fixed-price transactions executed in the past three years (n-3, n-2, n-1) for delivery in the following three years (n, n+1, n+2).
- We direct Staff to propose, by the end of 2020, a method to include long-term fixed-price transactions in calculating the RPS Adder.
- With respect to the local RA, the Adder will require including data from year (n-3) to keep it consistent with the current RA compliance requirements.

5.1.1. Scoping Memo Issue 4: Proposal

Working Group One co-chairs propose the following methodological and procedural approach to calculate the forecast Market Value of a portfolio of energy resources based on three Market Price Benchmarks: Energy Index, RPS Adder, and RA Adder. As noted previously, each Market Price Benchmark must be multiplied by the relevant volume to compute a value measured in dollars.

Forecast Energy Value: For purposes of calculating the Energy Index, the co-chairs propose maintaining existing practice of relying on Platts average published peak and off-peak market indices for a one-year strip of power for the coming calendar year (year n) for North of Path 15 (NP15), for PG&E, and South of Path 15 (SP15), for SCE and SDG&E, published over the period of October of the year prior to the forecast year, as directed in D.18-10-019. This average is separately calculated for NP15 and SP15 and weighted using peak and off-peak weighting factors that reflect bundled customer load to derive a separate Energy Index for each IOU.

As explained in the May Report, forecasted energy revenues are used in each IOU's annual ERRA Forecast filing to determine the total portfolio indifference amount for the following year n. Forecasted energy revenues are calculated by multiplying the Energy Index ($/MWh) by the forecasted energy generation (MWh) from the IOUs' PCIA-eligible resources.

Forecasted RPS Value: The value of RPS attributes is forecasted using the prices and quantities for three RPS product categories within the PCIA-eligible portfolio:

Table II: Price and Quantities for the RPS Product Categories

RPS Product Category	**Price**	**Quantity**
Forecast Retained	Forecast RPS Adder, calculated by Staff	Forecasted IOU RPS compliance need
Actual Sold	Actual transacted price for any transactions up to ~45 days prior to ERRA Forecast filing (November update)	Actual transacted volume of transactions up to ~45 days prior to ERRA Forecast filing (November update)
Forecast Sold	Applicable RPS Adder	Forecasted sold volume

Regarding the approach to calculate the RPS Adder, the co-chairs propose using the volume-weighted average of all IOU, CCA, and ESP market transactions (using only Portfolio Content Category 1 (PCC 1) index-plus contracts) executed in the fourth quarter (Q4) of year (n-2), and the first through the third quarter (Q1-Q3) of year (n-1) for delivery in year n. For example, the Forecast RPS Adder for the 2020 compliance year is based on sales from Q4 2018 through the third quarter (Q3) of 2019, for delivery in 2020. The calculation will be performed by Staff at the beginning of November each year and will be incorporated into the IOUs' annual ERRA Forecast Applications.

According to the May Report, during the working group process, TURN raised the issue of integrating long-term fixed-price power purchase agreements (PPAs) into the RPS Adder calculations. Pointing to the potential disconnect between short-term prices for existing projects and long-term pricing for new RPS resources, TURN argues that the failure to consider these transactions and relying on "index-plus" transactions could skew the MPB and result in biased RPS Adders. However, recognizing the technical challenges to developing a workable methodology for incorporating fixed-price transactions, TURN accepts the proposed index-plus approach as an interim solution. Furthermore, TURN recommends that the Commission require all LSEs to provide Staff with 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). According to TURN, data for each fixed-price bundled transaction should include price, contract duration, delivery node, hourly delivery profile and RA value. TURN also calls for a sunset date for using the co-chairs' proposal, but does not propose a specific date.

Forecast RA Value: The value of RA resources is forecasted using the prices and quantities for the following categories within the PCIA eligible portfolio:

Table III: Forecast RA Price and Quantity[8]

	Price ($/kW-year)	Quantity (MW)
Forecast Retained RA	Forecast RA Adder, as calculated by Staff	Final RA allocations and the amount retained for IOU use
Actual Sold RA	Actual transacted price for transactions up to ~45 days prior to ERRA Forecast filing	Actual transacted volume for transactions up to ~45 days prior to ERRA Forecast filing
Forecast Sold RA	Applicable RA Adder	Forecasted sold volume
Forecast Unsold RA	PG&E's proposal - $0 CalCCA's proposal – Floor price, if any, otherwise $0	Forecasted unsold volume

The co-chairs disagree on the definition and valuation of unsold RA products. The issue will be addressed in Section 5.5.

Regarding the approach to calculate the Forecast RA Adder, the co-chairs propose that Staff calculate and publish the Forecast RA Adder for year n at the beginning of November in year (n-1). The data requirements for this approach are as follows:

1. For flexible and system RA, Forecast RA Adder is calculated using the volume-weighted average of all IOU, CCA, and ESP RA-only market transactions executed in Q4 of year (n-2), and Q1-Q3 of year (n-1) for delivery in year n. The annual RA Adder ($/kW-year) is the sum of the monthly weighted average of the relevant transactions (*i.e.*, for system, all non-local, non-flexible transactions executed within the execution window for delivery in year n).

[8] Based on Table 1a and 1b of the May Report.

2. Because LSEs currently have a 3-year forward local RA requirement beginning in compliance year 2020, the timing of the calculation will be as follows: The forecast 2020 local RA Adder will be calculated for each IOU TAC area using LSE RA-only market-based transactions executed in Q4 of year (n-2), and Q1-Q3 of year (n-1) for delivery in year n. For delivery in 2021 and beyond, the calculation will use transactions executed in years (n-1) and (n-2) for delivery in year n. The annual RA Adder ($/kW-year) is the sum of the monthly weighted average of the relevant transactions, e.g. system, non-local, non-flexible transactions executed within the execution window for delivery in year n.

Even though the co-chairs initially disagreed on whether Capacity Procurement Mechanism (CPM) costs and revenues should be included in the RA Adder, they eventually agreed to exclude CPM costs and revenues from the RA Adder calculation and record CPM revenues in PABA.

5.1.2. Scoping Memo Issue 4: Party Comments

Several parties addressed excluding fixed-price bundled transactions from the RPS Adder; specifying the dataset needed to calculate the RA Adder; and including CPM costs to the MPB calculation.

Fixed-price bundled transactions: Several parties, including, TURN, CLECA, Public Advocates Office, and Shell, support either the inclusion of long-term fixed-price PPAs or continued work to develop a method to incorporate such transactions into RPS Adder calculations. Towards that end, Public Advocates Office recommends that the Commission adopt TURN's proposal to establish a requirement that all LSEs also be required to provide Staff with information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2, n-1) for delivery in the following years (n, n+1, n+2).

In response to TURN's proposal, IOUs and CCAs have noted that (1) the majority of the current RPS transactions are PCC 1 index-plus contracts; and (2) including fixed-price contracts into the RPS Adder may require many administratively-determined assumptions that could lead to unexpected results, *e.g.*, $0 or negative PCC 1 REC prices, despite positive REC market values. The co-chairs believe that TURN's approach does not align with the intent of D.18-10-019, because an administratively-set price is inconsistent with D.18-10-019's emphasis on market transactions for the benchmark calculation. Acknowledging TURN's concerns about a possible market shift away from index-plus transactions towards long-term fixed-price transactions, the co-chairs agree with TURN that the appropriate approach is to go forward with using only index-plus transactions, while Staff collect data on long-term fixed-price transactions. Noting that any Commission imposed sunset date would be arbitrary and has not been discussed in the working group process, the co-chairs recommend that the Commission not impose a sunset date at this time. The co-chairs recommend that Staff monitor the state of the market to determine, if and when, it is appropriate to revisit the RPS Adder.

Data for RA Adder: With respect to developing the local RA Adder, SCE and SDG&E note that the Commission's new local multi-year RA rules adopted in D.19-06-026 require LSEs demonstrate RA compliance in compliance year n for 100% of the LSE's needs for year (n+1) and year (n+2), and 50% of the LSE's needs for year (n+3). In their view, transactions that inform the benchmarks should match those required by the new rules. Therefore, both utilities argue that the co-chairs' proposal would omit relevant transactions from the local capacity benchmark and create a mismatch between the forecasts and subsequent true up.

CPM: On the issue of including CPM costs, the City of San Diego and POC support incorporating CPM costs into forecast RA Adder calculations. Considering CPM costs as actual costs, these parties argue that nothing in the Commission's decision regarding the PCIA calculation requires the exclusion of CPM costs. In contrast, Joint IOUs, TURN, and CLECA oppose including CPM costs into the RA Adder calculation, stating that (1) D.18-10-019 clearly indicated that CPM costs should not be included in RA Adder calculations; (2) CPM costs are not a good proxy for the RA market, as CAISO invokes CPM even when LSEs have fully complied with RA requirements; and (3) CPM revenues are already captured in an IOU's PABA.

5.1.3. Resolution of Scoping Memo Issue 4

Forecast Energy Value: We confirm that the methodology for Forecast Energy Value remains the same. The proposal is consistent with D.18-10-019, which provides that the "Brown Power Index" remain unchanged.[9] We note that the methodology for calculating the "Brown Power Index" was established in D.06-07-030; D.11-12-018 modified the calculation to reflect bundled customer load; and D.18-10-019 kept the methodology the same.

Forecast RPS Value: We adopt the forecast approach described in the May Report; however, we also conclude that including fixed-price contracts in the RPS Adder calculation is a desirable approach and that additional work is needed to develop a methodology to include them.

D.18-10-019 stated that a revised RPS Adder that is calculated using the reported prices of purchases and sales of renewable energy by the IOUs, CCAs,

[9] D.18-10-019 at 73.

and ESPs would produce reasonably accurate estimates.[10] Overall, the co-chairs' proposed approach complies with the direction given in D.18-10-019. Due to the complexities of integrating fixed-price long-term RPS contracts, the proposal keeps the calculation of forecast RPS Adder limited to index-plus transactions.

The Commission recognizes TURN's concerns regarding exclusion of fixed-price contracts and agrees that including fixed-price contracts in the RPS Adder calculation is the directionally appropriate policy. Because LSEs are now required by statute to comply by 2021 with a 65 percent long-term contracting requirement, incorporating long-term bundled contracts (contracts that include both energy and Renewable Energy Credits) into the RPS Adder calculation is expected to more accurately reflect RPS goals,[11] thereby producing more accurate estimates. With the goal of eventually updating the RPS Adder to include fixed-price contracts, we take the following steps:

1) We adopt TURN's proposal that all LSEs be required to provide Staff with 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).[12] As noted by Public Advocates Office, this information will provide Staff with insight into whether the proposed index-plus approach to the RPS Adder accurately reflects the market for fixed-price contracts over time. This effort will allow Staff to monitor the impact of

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[10] D.18-10-019 at Findings of Fact 3.

[11] Public Utilities Code Section 399.13(b) provides the following:

A retail seller may enter into a combination of long- and short-term contracts for electricity and associated renewable energy credits. 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.

[12] Public Utilities Code Section 701.

fixed-price long-term transactions on the RPS Adder; assess the feasibility of incorporating such transactions into the RPS Adder calculations; and allow Staff to propose, by the end of 2020, a method to include fixed-price contracts in calculating the RPS adder for Commission's consideration.. We authorize the Energy Division Director to hold workshops or utilize the existing Working Group process to develop this proposal.

2) Because the process of replacing the current approach with a new method that is simple, easy to administer, yet accurate, will require significant resources from the Commission and the parties, we do not adopt a sunset date for the adopted approach at this time. The adopted approach will be maintained until a replacement methodology is in place.

Forecast RA Adder: The Commission finds the proposal to forecast RA Adder for system and flexible RA reasonable and adopts it. D.18-10-019 found that a revised RA Adder that is calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions would produce reasonably accurate estimates if a zero or *de minimis* price is assigned for capacity expected to remain unsold.[13] The Commission also found that the revised RA Adder will be more accurate if it is calculated in a manner that reflects the three types of RA capacity: system, local, and flexible.[14] The proposed approach for system and flexible RA complies with the direction provided in D.18-10-019.

With respect to calculating the RA Adder for local RA resources, we do not adopt the co-chairs' proposal that includes only year (n-1) and (n-2) transactions. We find that it is reasonable to add transaction data from year (n-3) in order to incorporate transactions taken pursuant to the three-year forward-looking RA

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[13] D.18-10-019 at Findings of Fact 4.

[14] D.18-10-019 at Findings of Fact 5.

obligations. We recognize that three-year old data does not reflect the most current market transactions or prices. But, including data from year (n-3) will ensure that the calculated values reflect the value of the transactions entered into pursuant to the current multi-year local RA requirements. The data requirements we adopt are listed in Attachment A.

On the issue of excluding CPM costs from calculations, the Commission concludes that the CPM transactions should continue to be excluded from the RA Adder calculation. CPM is a CAISO procurement mechanism used to backstop the RA program. This mechanism helps to ensure that there is sufficient capacity available to meet the CAISO's forecasted needs after bilateral market transactions have been procured and shown. There are a variety of situations that provide CAISO the authority to issue a CPM designation, including insufficient local capacity resources, collective deficiencies in local areas, a significant event, and a reliability or operational need for exceptional dispatch.[15] Therefore, we agree with the Joint IOUs that CPM transactions reflect backstop procurement costs and does not present a fair representation of RA market prices. In addition, the actual CPM revenues that may be received by a utility through a CPM designation are already captured in the PABA.

Finally, as CLECA and TURN noted, D.18-10-019 did not intend to include CPM costs in the MPB for capacity and expressed this intention by adopting TURN's proposal. Therefore, we do not see any compelling argument to revisit the issue. We confirm that CPM costs must be excluded from the RA Adder calculations.

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[15] CAISO Tariff 43A.

5.2. Transaction Reporting for Forecasting and Truing Up Adders (Scoping Memo Issues 5 and 2)

Scoping Memo Issue 5 asks whether the Commission should modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how this should be accomplished. Scoping Memo Issue 2 asks whether new data and/or transaction reporting are requirements needed for the purposes of performing the true up; and if so, what those data/reporting requirements are and how they should be considered by the Commission.

The Commission concludes that new data templates for collecting the data needed to calculate the RA and RPS Adders may be necessary to enable Staff to accurately calculate forecast and final Adders. In the interest of administrative efficiency, we authorize the Energy Division Director to use the proposed templates, modify them, develop new templates, use data currently being submitted for compliance purposes, or issue supplemental data requests in order to collect sufficient and accurate data for the purpose of developing forecast and final Adders.

5.2.1. Scoping Memo Issues 5 and 2: Proposal

Working Group One proposes the following: For the purposes of forecasting benchmarks, Staff will calculate the Energy Index, RA Adder and RPS Adder annually for both the forecast and true up. This data will be collected and calculated by November of each year for the IOUs to incorporate in their annual ERRA Forecast Applications.

For the Energy Index, values will be provided from Platts forward prices, which will maintain the current practice. The RA and RPS Adders are based on data collected through quarterly data requests to the LSEs which include both sale and purchase transactions. The proposed draft data request templates have been developed through collaboration with the co-chairs and Staff and were presented at multiple working group public meetings. The co-chairs note that in the future, Staff will have the options to conduct data requests less frequently than quarterly as parties and Staff become familiar with the forms and the data collection process.

For the purposes of the RA Adder, a new PCIA-specific data reporting template will be used instead of combining the PCIA data request with that used for obtaining data for the Energy Division's Annual RA Report.

5.2.2. Scoping Memo Issues 5 and 2: Party Comments

The May Report states that a number of stakeholders expressed concerns related to confidentiality protections for commercially sensitive data used to develop the market price benchmarks. For example, Commercial Energy argues that only Staff should have access to data responses and that after calculating the benchmark, data should be destroyed or returned.[16] Similarly, AReM/DACC and CLECA support destruction of confidential data after calculations are complete.[17] Objecting to LSEs having to submit RA and RPS price data to the Energy Division, Shell proposes that data should be reported to an index developer representing a liquid platform for trading RA and RPS products that will make the market more competitive and open.[18]

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[16] Commercial Energy, Informal Comments, April 2, 2019, at 2 (May Report Exhibit E).

[17] AReM/DACC, Informal Comments, March 8, 2019; CLECA, Informal Comments, March 8, 2019 (May Report Exhibit F).

[18] Shell Energy, Informal Comments, April 2, 2019, at 1 (May Report Exhibit E).

On the other hand, TURN argues that the data access should not be limited to Staff and the Commission should provide non-market participants (NMPs) with equal access to confidential information submitted by CCAs, ESPs and IOUs.

5.2.3. Resolving Scoping Memo Issues 5 and 2

We find the Working Group One proposal on RA and RPS data templates reasonable. However, modifications to the proposed templates or new data templates may be necessary to enable Staff to accurately calculate forecast and final Adders. In the interest of providing Staff flexibility and maintaining administrative efficiency, we authorize the Energy Division Director to use the proposed templates, modify them, develop new templates, use data currently being submitted for compliance purposes, or issue supplemental data requests in order to collect sufficient and accurate data for the purpose of developing forecast and final Adders.

Collecting data on both sales and purchases may help identify instances when LSEs fail to fully and accurately report their transactions. To ensure there is no double counting of transactions, Staff should take the necessary steps to remove duplicate transactions (the same transactions, purchase and sale, reported by two LSEs) in calculating the RA and RPS Adders.

Regarding the frequency of the data collection, the Commission finds that reporting as frequently as quarterly may be necessary for numerous reasons. For example, all LSEs and Staff need to familiarize themselves with the template and calculations. This necessity may vary over time; therefore, in the interest of administrative efficiency, we authorize the Energy Division Director to adjust the frequency of the data reporting based on the data needs and availability of Commission resources to collect and process data.

The proposal calls for data templates that are developed for the purpose of calculating RA and RPS Adders for the PCIA calculation and are supplemental to those currently used for collecting RA and RPS data. In the interest of administrative efficiency, we authorize the Energy Division Director to either use RA and RPS data currently being submitted by LSEs for compliance purposes or issue supplemental data requests, or both, as needed, in order to collect sufficient and accurate transaction data for calculating the forecasted and final Adders.

Several parties expressed concerns regarding submitting confidential data to Staff for the purpose of calculating the market price benchmarks and suggested additional measures to keep data confidential. We do not see any compelling reason to revisit the issue herein. General Order (GO) 66-D sets out the general procedures for requesting confidential treatment of information submitted to the Commission. D.06-06-066 establishes consistent treatment and procedures for potentially confidential information that is primarily related to procurement activities.[19] In this proceeding, confidentiality of market-sensitive data and applicability of the procedures set by D.06-06-066 to CCAs have been addressed by the March 20, 2019 ALJ Ruling. We confirm the March 20, 2019 ALJ Ruling that all data submitted to Staff by LSEs is entitled to confidentiality protections as prescribed by D.06-06-066, et al., and do not find a need for additional procedures.

The issues within the scope of this proceeding are complex and require quantitative work. For an NMP to participate in the stakeholder process in a meaningful and efficient manner, NMPs should be able to have access to data,

[19] D.06-06-066 was modified by D.07-05-032 and D.08-04-023.

provided they agree to a protective order. Therefore, we find TURN's proposal to give NMPs access to confidential data reasonable and encourage all ESPs to share that data under a NDA or protective order, but do not require ESPs to do so. As TURN noted, providing NMPs access to confidential data is consistent with Public Utilities Code Section 454.5(g) and D.06-06-066.[20] The access rights are already established in D.06-06-006 and they remain in place. D.08-04-023 adopted a model protective order and non-disclosure agreement for all procurement-related data, but did not obligate parties to use it.[21] Interested parties may develop a common non-disclosure agreement (NDA) that can be used for confidential material submitted by any ESP, CCA, or IOU relating to the development of the market price benchmarks.

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[20] D.06-06-006 at Ordering Paragraph 11 states: "Intervenor groups that are non-market participants shall not be precluded from access to any ESP or IOU data as long as they agree to a protective order or confidentiality agreement where there is a need to protect the data."

Public Utilities Code Section 454.5(g) provides: "The commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan, including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination, provided that the Public Advocate's Office of the Public Utilities Commission and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission."

[21] D.08-04-023 at OP 1:

"With this decision, we adopt a model protective order and non-disclosure agreement (Model), attached to this decision as Appendix A, for use with confidential documents governed by this proceeding. Parties to other proceedings, and in industries other than the electric sector, may find the Model useful as well, although we will not obligate them to use it. Parties to the Resource Adequacy (RA), Procurement, Renewables Portfolio Standard (RPS) and offshoot or successor proceedings shall use the Model. These proceedings bear the following docket numbers: Rulemaking (R.) 08-01-025, R.05-12-013 and R.04-04-003 (RA); R.06-02-013 (Procurement); and R.06-05-027, R.06-02-012, and R.04-04-026 (RPS)."

A standardized NDA is reasonable for efficiency and equal access to all confidential information.

5.3. True Up of the Brown Power Component, the Resource Adequacy (RA) Adder and the Renewable Portfolio Standard (RPS) Adder of the Market Price Benchmark (Scoping Memo Issue 1)

Scoping Memo Issue 1 asks which mechanism(s), procedural and/or methodological, the Commission should adopt to true up annually the Brown Power component, the RA Adder and the RPS Adder of the MPB. Restated using the naming conventions of this decision, Issue 1 asks which mechanism(s), procedural and/or methodological, the Commission should adopt to true up annually the Energy Value, the RA Value and the RPS Value used to calculate the PCIA, including the component Market Price Benchmarks (Energy Index, RPS Adder, and RA Adder).

As discussed below, it is reasonable to adopt the co-chairs' proposal for the energy true up as recommended in the May Report. We also adopt the proposal for truing up the RA Adder for system and flexible RA, but not for local RA; the proposal for local RA excludes data from year (n-3) and does not reflect the current local RA requirement horizon. For truing up the RPS Adder, we find the overall approach reasonable. However, on the unsold RPS issue, we adopt PG&E's proposal that will assign unsold RPS a zero value, until a Commission decision makes a decides on the sale of RPS attributes.

5.3.1. Scoping Memo Issue 1: Proposal

Energy Value True Up: According to the proposal, revenue is trued up for year n based on the realized net CAISO revenues for all PCIA-eligible resources, including revenues received through CAISO's CPM, if any. There is no Energy Index used in the true up process. The realized revenues are recorded to the vintaged resources' respective vintaged PABA subaccount and become an offset to the actual costs recorded in those subaccounts. The year-end over- or under-collection in the vintaged PABA subaccounts for year n are included in the vintaged PCIA rate calculation for year (n+1). The true up process is addressed as part of the annual ERRA Forecast proceeding.

RPS Value: Actual RPS Value for use in the true up is calculated using the prices and quantities in the following categories of RPS within the PCIA-eligible portfolio as part of the annual ERRA Forecast proceeding.

Table IV: RPS Value True Up

Type of RPS Product	**Price**	**Quantity**
Actual Retained	Final RPS Adder, calculated by Staff	PG&E proposal: Volume used for IOU compliance from PCIA-eligible portfolio CalCCA proposal: Volume generated from the PCIA-eligible portfolio minus generation sold from the PCIA-eligible portfolio
Actual Sold	Actual transacted price	Actual transacted volume
Actual Unsold[22] (PG&E proposal)	PG&E proposal: No credit	PG&E proposal: Actual unsold volume

RPS Value for products that are sold is the revenue earned from the sale. RPS Value for products that are retained is the imputed value based on the RPS Adder. RPS Value is allocated by vintage according to the methodologies and order described below:

[22] The co-chairs disagree on the valuation of unsold RPS, but they agree that the general principles apply to RECs generated commencing January 1, 2019 and going forward.

1. For revenue from Actual Sold RPS that is resource specific, revenue is allocated in the forecast to the corresponding resource specific vintage and recorded in the true up to the corresponding resource specific PABA vintage subaccount.

2. For revenue from Forecast Sold RPS and Actual Sold RPS that is not resource specific, revenue is allocated in the forecast and recorded in the true up to the PABA vintage subaccounts on a pro rata basis.[23]

3. For Forecast Retained RPS and Actual Retained RPS, the value is imputed market value based on the RPS Adder rather than revenue. The imputed revenue is allocated pro rata in the forecast and recorded in the true up to the PABA vintage subaccounts on a pro rata basis.

There is disagreement between the co-chairs on the quantity and price of Actual Unsold RPS. According to PG&E, unsold RPS quantity should be determined in the following manner: Each IOU identifies the RPS resources offered for sale to an IE[24] and its PRG[25] in advance of when bids are due and documents the quantity offered in the Advice Letter seeking approval of transactions resulting from the solicitation. The RPS resources offered for sale are consistent with the RPS Plan, as may be modified or supplemented through Commission-approved filings, each of which is reviewed and approved by the

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[23] This pro rata allocation is on a total PCIA-eligible portfolio basis and will be calculated by the total product positions, by vintages, as included in the pending or authorized annual ERRA forecast.

[24] In D.04-12-048 and D.07-12-052, the Commission directed the IOUs to use an independent evaluator to monitor competitive solicitations that involved affiliate transactions and long-term transactions.

[25] In D.02-08-071, the Commission required each utility to establish a Commission-authorized Procurement Review Group in order to ensure that interim procurement contracts entered into by the utilities are subject to sufficient and expedited review.

Commission with opportunity for stakeholder participation. Any of the offered quantity that is not sold will be considered as Actual Unsold RPS and should not be assigned credit in PABA until the value of the RPS product, if any, is known. If previously unsold RPS is sold in a future year, it should be valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it should be valued at the applicable future year's RPS Adder. If Unsold RPS is never used, it should not be assigned credit.

In disagreement, CalCCA proposes using only two categories of RPS, Retained and Sold RPS, which do not require determining when RPS attributes are "unsold." According to CalCCA, Unsold RPS product should be valued at the benchmark. CalCCA argues that all retained RPS should be treated equally, regardless of the reason for retention, including any "unsold" RPS. According to CalCCA, this approach (1) avoids disputes over the adequacy of IOU sales efforts, which is currently under consideration in Working Group Three; and (2) it is administratively simple to implement. CalCCA asserts that, under PG&E's proposal, the lag between REC creation and PABA credit, if any, will be long, and uncertain. During that period, such "unsold" RPS would receive no value for PCIA purposes, thereby inflating the PCIA rate.

RA Value True Up: Actual RA Value is calculated for Actual Retained RA, Actual Sold RA, and Actual Unsold RA products using the prices and quantities listed in Table V within the PCIA-eligible portfolio. As indicated, co-chairs disagree about the definition and valuation of unsold RA.

Table V: RA True Up

	Price	Quantity
Actual Retained RA (Not offered into the market; kept by the IOU for compliance)	Final RA Adder, as calculated by Staff	RA used for compliance and the amount retained for IOU use
Actual Sold RA	Actual transacted price	Actual transacted volume
Actual Unsold RA	PG&E's proposal: $0 CalCCA's proposal: Price floor used in the solicitation, if any; otherwise, $0.	PG&E's proposal: Quantity offered for sale but not sold or used by IOU CalCCA's proposal: Quantity offered for sale by the end of August preceding the compliance deadline for the relevant year

For each type of RA Adder, Staff calculate and publish the final RA Adders for year n at the beginning of November of year n. The method for calculating final RA Adder for system and flexible RA is the same as for calculating forecast RA Adder except that the transactions from Q4 of year (n-2) are excluded and the data is supplemented with transactions executed in Q4 of year (n-1) for delivery in year n and transactions executed in Q1-Q3 of year n for delivery in year n. Another component of the co-chairs' proposal is that, unless a central buyer structure for procuring RA is adopted, the true up of the RA Adder for Local RA is based on the same data requirements as calculating the Forecast Adder for Local RA. The year-end over- or under-collection in the vintaged PABA subaccounts related to RA categories for year n is included in the vintaged PCIA rate calculation for year (n+1), as part of each utility's ERRA Forecast proceeding.

RA revenues for RA products that are sold or imputed market values for RA products that are retained are allocated by vintage according to the methodologies and order described below:

1. For revenue from Actual Sold RA that is resource specific, revenue is allocated in the forecast to the corresponding resource specific vintage and recorded in the true up to corresponding resource specific PABA vintage subaccount.

2. For revenue from Forecast Sold RA and Actual Sold RA that is not resource specific, revenue is allocated pro rata in the forecast and recorded in the true up to the PABA vintage subaccounts on a pro rata basis.

3. For Forecast Retained RA and Actual Retained RA imputed market value, the imputed market value is allocated pro rata in the forecast and recorded in the true up to the PABA vintage subaccounts on a pro rata basis.

The pro rata allocation for RA is based on the quantity of RA MW for each type of RA (system, flexible, and local) in each vintage. For example, if the 2009 vintage has 10 percent of the total system RA MWs in the PCIA portfolio, 10% of the revenues would be allocated to the 2009 vintage in the forecast and recorded to the 2009 PABA vintage subaccount in the true up.

5.3.2. Scoping Memo Issue 1: Party Comments

Energy Value True Up: The proposal for energy value true up is uncontested.

RPS Value True Up: Party views differ on the value of unsold RPS. Several parties support CalCCA proposal and argue that unsold RPS has value. For example, AReM/DACC argues that RPS products (RECs) should be valued at the RPS MPB at the time that they are generated. According to AReM/DACC, tracking how much is "consistent" with the IOU's RPS plan and valuing only when, or if, withdrawn from the RPS bank is cumbersome and potentially allows for gaming. The City of San Diego also finds CalCCA's proposal to be more reasonable. Noting that true up is an annual activity, the City of San Diego argues that the forecasted PCIA needs to be trued-up based on actions in the past year, not some undefined actions that might occur in the future.

POC also agrees that sold RPS should be valued at the transaction price. Claiming that PG&E has an incentive to retain only the resources with the most desirable characteristics, and sell only those with the least desirable characteristics, POC asserts that the retained and desirable resources would be valued at the RPS Adder's average market price, which is POC claims, is below their actual value.

In contrast, Joint IOUs claim that unsold RPS has zero value. Joint IOUs argue that the CalCCA alternative would require bundled customers to

1) impute revenues to departing load customers for RPS products the IOUs' bundled service customers do not need and the market does not want; and

2) compensate departing load customers for products lacking market value, shifting costs to bundled service customers.

Joint IOUs note that frameworks prescribing the processes for portfolio sales, including RPS sales, are in scope for Working Group Three. Joint IOUs explain that unsold RPS products that are offered for sale and remain unsold after generation may have value subsequently if they are 1) used to exceed compliance requirements by an IOU, 2) retired to an IOU RPS bank for hypothetical future use if an IOU is short, or 3) sold for a lower value compliance product, i.e., sold as an unbundled renewable energy credit. Unsold RPS products also may have no value if they 1) expire or 2) are banked by an LSE that is not able to use them for compliance. Given this uncertainty, Joint Utilities argue, the value of the marketed REC that remains unsold cannot be assigned or imputed to the bundled service customer unless and until it is sold or is used for the benefit of the bundled portfolio.

In TURN's view, it is possible that the IOUs may retain RPS for contingency or other purposes; in such cases, TURN argues, a *de minimis* price may be appropriate to value such resources for the PCIA calculation. TURN does not believe this issue was explored in the workshop process.

RA Value True Up: Several parties, including TURN, SDG&E, and CLECA, commented on the true up method for RA Value. Parties' main concern on the co-chairs' proposal is that using the same transaction dataset for forecast and true up of the Local RA adder and not updating to reflect transactions that occur in year n, makes the adder static and would eliminate any true up of the Local RA benefits and costs. Failing to true up the local RA capacity adder is also contrary to D.18-10-019, which seeks to true up forecasts with actual values. These parties propose that the true up methodology for the Local RA adder should (i) include all transactions utilized in the forecast Local RA adder, as well as additional transactions executed in the first quarter (Q1) through Q3 of year n for delivery in year n; and (ii) include transactions in year (n-3) in the market price benchmark calculation.

5.3.3. Resolving Scoping Memo Issue 1

In D.18-10-019, the Commission adopted a true up mechanism for Energy Value, but determined that it should not adopt true up mechanisms for RA Value and RPS Value due to insufficient record.[26] The Commission found that a true

[26] D.18-10-019 Findings of Fact 16.

up mechanism will increase the accuracy of the PCIA cost allocation between bundled and departing load customers.[27]

For the Energy Value true up, we adopt the proposal presented in the May Report. The proposal is easy to implement; is based on actual revenues; maintains the current practice; and therefore, it is consistent with D.18-10-019.

With respect to the RPS Value true up, the Commission adopts PG&E 's recommendation to assign a zero value to unsold RPS. The IOUs' RPS procurement planning takes place in formal proceedings subject to stakeholder review. The Commission may authorize the IOUs to retain RPS resources based on their procurement planning needs. If the IOUs use RECs in the future based on their 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, as TURN notes, could conflict with the Commission-approved procurement plans. It effectively shifts market risks and opportunities associated with changing REC prices to bundled customers even though the resources generating those RECs were not procured solely on their behalf. Further, valuing all retained or unsold RECs at this time might be perceived as prejudging the ultimate outcome on Working Group Three's proposal 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.

The Commission could issue a decision on portfolio optimization that modifies its current rules, but until then, we find that it is reasonable to adopt a zero value for unsold RPS.

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[27] D.18-10-019 at Findings of Fact 15.

With respect to the local RA Value true up, the co-lead proposal does not provide sufficient reasoning for limiting the transaction time dataset. Because the intent of the true up process is to improve the accuracy of the values used in the ERRA forecast, we find that it would be more accurate to include transactions covering the full local RA requirement horizon. This includes transactions taking place in year (n-3), (n-2), (n-1) as well as year n, as shown in Attachment A.

We should note that the true-up process required by D.18-10-019 does not mean entirely replacing Market Price Benchmarks with actual prices from purchases and sales. Even in the true-up process, Market Price Benchmarks are needed for estimating value that is unknown because the underlying products have not been financially transacted. For example, if a utility retires RECs in a given year, there is no financial transaction to establish the price of those RECs at the time of retirement. Therefore, an estimate of the price, or Final RPS Adder, must be developed in order to assign a value that can be used in the true up of those products from the previous year. In contrast, for RECs that a utility purchases or sells, the actual price can be used in the true up process, and no benchmark is needed.

5.4. The True Up Process (Scoping Memo Issue 3)

Scoping Memo issue 3 asks whether the true up process should be addressed as part of the annual ERRA proceedings. We determine that the true up process should take place as part of the ERRA Forecast proceedings.

5.4.1. Scoping Memo Issue 3: Proposal

As indicated in the May Report, the co-chairs agree that the true up process should take place as part of the ERRA Forecast proceeding. Accordingly, they propose the RA and RPS Value calculation and reporting structure around the timing of the November ERRA Forecast filings. Any over- or under-collections are rolled into the following year's PCIA rate, which are filed within the ERRA Forecast Update.

5.4.2. Scoping Memo Issue 3: Party Comments

The proposal is uncontested.

5.4.3. Resolving Scoping Memo Issue 3

We find the proposed approach reasonable and confirm that the true up of each vintage portfolio's Market Value for each year, including the Energy Index, RPS Adder, and RA Adder should occur as part of the ERRA Forecast proceeding. The PCIA forecast has historically been calculated in each IOU's ERRA Forecast proceeding. No party provided any compelling reason to change that for the true up calculation. This proceeding and other proceedings will have impacts on the factors that are considered in calculating the RA Value and the RPS Value. But the true up of the Market Value used in the PCIA calculation, including the Energy Index, RA Adder, and RPS Adder should be addressed as part of the annual ERRA Forecast proceedings.

5.5. Quantity and Price of Unsold RA (Scoping Memo Issues 6 and 7)

In D.18-10-019 the Commission determined that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB."[28] Scoping Memo Issue 6 asks how the Commission should clarify or define the quantity of unsold RA for forecasting and true up purposes. Scoping Memo Issue 7 asks whether further parameters are needed to define a *de minimis* price, and if so, what these parameters are.

We conclude that PG&E's approach to defining and assigning value to unsold RA resources is reasonable, and hence, is adopted.

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[28] D.18-10-019 at Ordering Paragraph 1.

5.5.1. Scoping Memo Issues 6 and 7: Proposal

Working Group One co-chairs disagree on how to define and value unsold RA resources. According to PG&E's proposal, each IOU identifies the quantity of RA offered for sale to an IE and its PRG in advance of the bids due date and documents the quantity offered in its Quarterly Compliance Report.[29] The RA product is offered for sale in a solicitation process consistent with IOUs' approved Bundled Procurement Plan (BPP). Any of the offered quantity that is not sold is defined as Actual Unsold RA. RA that is offered for sale but remains unsold is not assigned any credit in PABA, regardless of whether an IOU uses floor prices in its solicitation.

CalCCA defines unsold RA as RA quantity offered for sale by the end of August preceding the compliance deadline for the relevant year, but not sold. Pending resolution of the issue by Working Group Three or other Commission decision, CalCCA supports valuing RA resources at the IOUs' price floor, if there is any, or zero, if there is no floor price.

5.5.2. Scoping Memo Issues 6 and 7: Party Comments

Several parties, including the Joint IOUs, CLECA, and Public Advocates Office, oppose CalCCA's Proposal for numerous reasons, including the following:

- If an IOU applies a price floor to RA sales, bundled service customers would be required to credit departing load customers for unsold RA value, when they receive none; thereby shifting costs to bundled customers.

[29] The Commission currently requires each IOU to submit a Quarterly Compliance Report via the Commission's advice letter process within 30 days of the end of every calendar quarter, in order for Commission Staff to review the IOU's procurement transactions for compliance with the Commission-approved procurement plans.

- CalCCA's proposal would lead to unreasonable portfolio management by providing an incentive not to apply price floors to RA sales, thereby increasing customer costs.
- CalCCA's proposal fails to recognize that bid floor can reflect the variety of different resources within a portfolio, with different expected costs. For example, a fossil unit with a low forced outage rate may have minimal expected costs, while a hydroelectric unit during a drought might expect relatively higher CAISO charges.
- CalCCA's alternative conflates bid floor with a *de minimis* price by applying the same price to capacity that remains unsold in the true up, making the proposal inconsistent with D.18-10-019. Pursuant to D.18-10-019, a potential *de minimis* price only applies to capacity expected to remain unsold in the forecast.
- CalCCA's recommendation could create a perverse incentive for the utilities to set the price below a reasonable price floor, which would in turn create a subsidy to the entity purchasing the capacity.
- Assigning the floor price sends the wrong market signals and could result in bundled and unbundled customers paying CAISO penalties.

In contrast, several parties support CalCCA's proposal. AReM/DACC believes that the floor price represents the minimum value placed on the RA resources. Therefore, in AReM/DACC's view, pending any resolution of this issue in Working Group Three, the unsold RA should be assigned a value equal to the IOUs' price floor (if there is one), or zero (if no floor). The City of San Diego also supports CalCCA's proposal and asserts that the IOUs have complete control over the setting of the floor price for its resource solicitations; if the IOU sets an unreasonably high floor price, then the floor price could very well be a major factor for RA resources remaining unsold.

In its comments, CalCCA clarifies that the Commission should deem RA volumes unsold, only if RA volumes are offered for sale in a meaningful timeframe prior to RA compliance deadlines. In CalCCA's view, the timing requirement ensures that the value of RA assets is maximized and a robust RA market is promoted. Under this revised proposal, RA will either be used or retained by the IOU for compliance, or it will be offered to market participants in time to meet those participants' own compliance requirements. As such, this requirement will ensure that bids in response to solicitations will garner appropriate sale prices. According to CalCCA, this approach is simple to administer and should avoid disputes over what amounts are eligible for "unsold" treatment in the PCIA.

TURN does not endorse either the PG&E or the CalCCA proposal, but notes the IOUs should have some obligation to make RA available on a known schedule and terms, but not necessarily at the earliest annual auction as CalCCA has initially proposed. TURN recommends that the specific obligation of IOUs to make RA available through regular scheduled auctions should be addressed in Working Group Three. Joint IOUs agree that any changes to the RA sale process should be considered within Working Group Three, and subsequently incorporated into IOU BPPs.

Regarding the value of the unsold RA, TURN considers a nonzero value to be appropriate, but questions whether the floor price is the proper value. TURN states that if a value greater than zero is to be estimated, further review of the IOUs' price floors or other possible values would be necessary.

5.5.3. Resolving Scoping Memo Issues 6 and 7

In D. 18-10-019, the Commission found a zero or *de minimis* price must be assigned for capacity expected to remain unsold for purposes of calculating the

MPB. Based on (1) the Commission's differentiation between a zero or *de minimis* value and (2) the plain meaning of "de minimis," one can argue that "de minimis value" should be taken as a value that is close to zero, but not zero. Neither the co-chairs nor the other parties have attempted to define parameters to specify a *de minimis* value. Instead, they focused on the zero value or the floor price, which is not necessarily close to zero.

We find that the Joint IOUs presented compelling arguments for why the floor price should not be designated as the *de minimis* value. However, we do not have sufficient record to designate any other positive value closer to zero as the "de minimis" value. Therefore, we adopt PG&E's proposal to set unsold RA value to be zero.

We disagree with CalCCA's proposal to have the quantity reflect the timing of the amount offered for sale by the end of August. Because 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. We agree with TURN that the specific obligation of IOUs to make RA available through regular scheduled auctions should be addressed by Working Group Three. Any changes to the RA sale process should be considered within Working Group Three, and subsequently incorporated into respective procurement plans. We agree with the Public Advocates Office in that, at a minimum, the IOUs should identify the quantity of RA offered for sale to an Independent Evaluator and its Procurement Review Group in advance of when bids are due. The IOUs should also document the quantity of RA offered for sale in the Quarterly Compliance Report and show that it is consistent with the Bundled Procurement Plan. In addition, the IOUs should demonstrate to the PRG that the RA floor price is set at a specific level in order to account for financial risks to ratepayers responsible for the corresponding costs, such as possible CAISO penalties. Further review of the IOUs' price floors or other possible metrics may also be taken up within Working Group Three efforts.

Determining a floor price in a solicitation requires consideration of several factors. One of these factors is the California Independent System Operator (CAISO) penalties, *e.g.*, Resource Adequacy Availability Incentive Mechanism costs. As explained by the IOUs, the IOUs would not sell RA resources below the floor price because the possible CAISO penalties for doing so could require the IOUs to recover costs in excess of the floor price from both bundled service and departing load customers. If the Commission were to assign the RA floor price value to unsold RA, it would be preferable for IOUs to sell their RA below the floor price and incur the penalties. This procurement action would violate the IOU procurement Standards of Conduct (SOC) 4 of the Procurement Manual, approved by the Commission. SOC 4 requires the utilities to prudently manage their portfolios. Selling RA below the floor price may not be the optimal portfolio choice when offsetting costs (*e.g.*, RAAIM penalties) of the sale are considered.

The example provided by Joint IOUs clearly illustrates this point:

> "Consider if an unsold resource has a contract cost of $10; if the capacity is supplied to the California Independent System Operator (CAISO) as RA then it becomes subject to the CAISO's non-availability standards (currently known as Resource Adequacy Incentive Mechanism (RAAIM) charges). For the purposes of this example, assume the unit has an expected RAAIM charge of $2 and that there are no other incremental costs to consummating the transaction. If the unit is then sold for $1, because no price floor was used, such a sale would result in an increase in total costs of $1. In this example, all customers paying the PCIA – both bundled service

> and departing load – will subsidize the entity that purchased RA for $1, and the above market cost of the portfolio increases from $10 to $11. A prudent portfolio manager, on the other hand, should set a price floor of $2.01 in the above example."[30]

In conclusion, use of a proper price floor in resource solicitations may maximize the value of the portfolio and is consistent with the Commission's procurement standards. CalCCA's proposal would provide a disincentive for the use of a price floor in an IOU solicitation. If a price floor is used and RA remains unsold, CalCCA's alternative would require IOU bundled customers to credit departed load customers for that RA at the price floor, shifting costs to bundled customers by requiring the bundled customers to buy resources they do not need. Hence, we do not adopt CalCCA proposal.

Further exploration of issues related to sale practices in Working Group Three should help us identify a balanced approach providing the right incentives for portfolio optimization while making sure that there is no cost shifting between bundled and departing load.

5.6. Billing Determinants (Scoping Memo Issue 11)

The Scoping Memo Issue 11 asks whether the Commission should clarify the definition of billing determinants and their proper usage for calculating the PCIA, and if so, how.

We approve the use of vintage-specific billing determinants. The actual use of vintage specific billing determinants shall be presented and approved in each utility's respective 2020 ERRA Forecast Application.

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[30] Joint IOUs, Informal Comments, May 29, 2019, at 4-5. (May Report Exhibit E)

5.6.1. Scoping Memo Issue 11: Proposal

The Joint IOUs request that the Commission approve the use of vintage specific billing determinants to calculate the vintaged PCIA rates and not rely on system sales. The proposal explains that using vintage-specific billing determinants would prevent undercollections accruing in the PABA subaccounts resulting from insufficient PCIA revenues. This proposal intends to timely and accurately recover total indifference amounts from both bundled service and departing load and reduce rate volatility.

The Joint IOUs' proposal is to divide the rate group-level vintaged PCIA revenue requirements by the forecasted rate group-level sales of those responsible for the vintaged portfolio to determine PCIA rates. The use of system level sales in the denominator used to set vintaged PCIA rates is not recommended because use of system sales result in lower rates than are necessary to collect the revenue requirement; thereby resulting in a systemic undercollection of the PCIA.

PG&E reports that in 2019, the use of system billing determinants results in bundled customers absorbing approximately $90 million to cover departing loads' share of the PCIA revenue shortfall.[31]

5.6.2. Scoping Memo Issue 11: Party Comments

There is support for the adoption of the Joint IOU proposal. AREM/DACC concur that the vintage billing determinants conform with the direction provided in D.18-10-019. Supporting the use of vintage sales rather than system sales as billing determinants, CLECA indicates that the vintage billing determinants proposed by PG&E and Southern California Edison (SCE) in their 2019 Energy

[31] The July Report at E-16.

Resource Recovery Account (ERRA) forecast proceedings (Application 18-06-001 and Application 18-05-003) are correct.[32]

5.6.3. Resolving Scoping Memo Issue 11

Currently, the IOUs are directed to divide each of the vintage portfolio indifference amounts by the sales of all system customers to determine the rates for each vintage portfolio. That is, vintage costs are divided by more sales than expected for that vintage rate group. Since sales by vintage are by definition lower than system sales, it is conceivable that there will always be an undercollection from departing customers. Even though this methodological error is corrected in the true up process, we do not find it reasonable to continue a rate design practice that repeatedly causes cost-shifting in the short-run.

We are convinced that the use of vintaged billing determinants will ensure that the forecast vintaged PCIA rates are designed to timely and accurately recover the total indifference amounts from both bundled service and departing load customers and will reduce the rate volatility caused by the application of the current methodology. Hence, we approve the use of vintage specific billing determinants.

The actual vintage-specific billing determinants shall be presented and approved as part of each utility's respective 2020 ERRA Forecast Application. We also direct SDG&E to give a presentation to Working Group One, providing information on the billing determinants SDG&E uses as contrasted with the use of vintaged billing determinants, within 30 days of the issuance of this decision, if it has not already provided this information to interested parties in this

[32] Because D.18-10-019 was silent on billing determinant modifications, SCE and PG&E were directed to continue to use system-level billing determinants in their PCIA forecast for the 2019 ERRA forecast proceedings.

proceeding. Similar presentations were given by SCE and PG&E to Working Group One participants.

6. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on September 26, 2019 by the following parties: AReM/DACC; CalCCA; the City of San Diego; the City of San Jose; CLECA; PG&E, SCE, and SDG&E; POC; Public Advocates Office; Shell Energy North America (US), L.P.; and TURN. Reply comments were filed on October 1, 2019 by the following parties: CalCCA; PG&E and SCE; POC; SDG&E; and TURN. In response, corrections and clarifications are made.

POC requests that SDG&E file its presentation on billing determinants with a Tier 2 Advice Letter. POC's request is denied. The actual vintage-specific billing determinants shall be presented and approved as part of each utility's respective 2020 ERRA Forecast Application.

CalCCA requests that an ordering paragraph be added to specify how to "true-up" the fourth quarter of the PABA forecast balance to actuals. CalCCA's request is denied. The Commission has ratemaking processes in place that will review and incorporate the updated balancing account activity.

7. Assignment of Proceeding

Marybel Batjer is the assigned Commissioner and Nilgun Atamturk is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. For purposes of calculating the Energy Value, the co-chairs propose maintaining the methodology adopted in D.18-10-019.

2. Relying on solely "index-plus" transactions and failing to consider long-term pricing for Renewables Portfolio Standard (RPS) resources in the RPS Adder calculations will not accurately reflect the evolution of the market toward long-term contracts.

3. There are technical challenges to incorporating fixed-price bundled transactions into Adder calculations.

4. Several parties support continued work to develop a method to incorporate fixed-price bundled transactions into RPS Adder calculations.

5. Load serving entities (LSEs) are required by statute to comply by 2021 with a 65% long-term contracting requirement for RPS procurement.

6. Incorporating fixed-price bundled transactions into RPS Adder calculations is expected to produce more accurate results and is directionally 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; assess the feasibility of incorporating such transactions into the RPS Adder calculations; and propose a method to incorporate fixed-price contracts into the RPS Adder calculations.

8. The methods adopted in this Decision apply to RECs generated commencing January 1, 2019 and going forward.

9. For flexible and system resource adequacy (RA), the approach proposed in Working Group One's May Report to calculate RA Value complies with the direction provided in D.18-10-019.

10. For local RA, there is a three-year compliance requirement starting in 2019 for 2020-2022 period.

11. The RA and RPS Adder calculations should be completed by Energy Division by the first business day in November in order to be incorporated into the IOU ERRA Forecast Application.

12. The Capacity Procurement Mechanism may not provide a fair representation of the market price.

13. Capacity Procurement Mechanism revenues are captured in Portfolio Allocation Balancing Accounts.

14. Although the data templates proposed by Working Group One are an outcome of the collaborative effort with Staff and generally appear sufficient to collect the necessary data, Energy Division needs the flexibility to revise them or develop new templates.

15. As LSEs and Staff familiarize themselves with the template and calculations, it may be necessary or desirable to collect data as frequently as quarterly, but Energy Division should have the discretion to collect data less frequently.

16. A standardized non-disclosure agreement is reasonable for efficient and equal access for nonmarket participants to all confidential information and the Commission encourages sharing of that confidential information.

17. Failing to true up the Local RA Adder is contrary to D.18-10-019, which seeks to true up forecasts with actual values.

18. Frameworks prescribing the processes for portfolio sales of excess resources, including RPS sales, are in scope for Working Group Three.

19. Joint investor-owned utilities (IOUs) explain that unsold RPS products that are offered for sale and remain unsold after generation may have value subsequently if they are: used by the IOU to exceed compliance requirements; retired to an IOU's RPS bank for hypothetical future use; or sold as lower value compliance products.

20. 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.

21. In any given year, the Commission may allow the IOUs to retain RECs based on their procurement planning needs.

22. RECs have value to the IOUs when they use the RECs. It is not clear under what circumstances costs may shift between bundled and unbundled customers when IOUs hold, do not sell, and do not use RECs.

23. 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.

24. 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.

25. The PCIA forecast has historically been calculated in each IOU's ERRA Forecast proceeding. No party provided any compelling reason to change that for the true up calculation.

26. The co-chairs of Working Group One disagree on the valuation of unsold RA and the definition of unsold RA product.

27. The co-chairs focused on zero and the floor price, but not on the parameters that will help define a *de minimis* price.

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

29. An investor-owned utility may decide not to sell RA below the floor price because the possible California Independent System Operator penalties for doing so could require the IOU to recover costs in excess of the floor price from both bundled service and departing load customers.

30. 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.

31. System sales are greater than sales within any given vintage.

32. When rate group-level vintaged PCIA revenue requirements are divided by the forecasted rate group-level sales of those responsible for the vintaged portfolio to determine PCIA rates, unless vintage sales are used in the denominator (rather than system sale), a systematic undercollection from departing customers will occur.

33. Using vintage billing determinants as opposed to system sales would help timely and accurately recover total indifference amounts from both bundled service and departing load and reduce rate volatility.

34. Even though this methodological error is corrected in the true up process, it is not reasonable to continue a practice that otherwise repeatedly causes cost-shifting in the short-run.

Conclusions of Law

1. The method to calculate Energy Value should remain as adopted in D.18-10-019.

2. The RPS Adder should be calculated using volume weighted average of all IOU, CCA and ESP market transactions using only Platts Portfolio Content Category 1 index-plus contracts executed in the fourth quarter of year (n-2), and the first through third quarter of year (n-1) for delivery in year n.

3. TURN's proposal should be adopted to require all LSEs to provide Staff with 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).

4. Energy Division should monitor the impact of fixed-price transactions and should, by the end of 2020, propose a method to include fixed-price contracts in calculating the RPS Adder. The Energy Division Director should be authorized to hold workshops or utilize the existing Working Group process to develop the proposal.

5. For flexible and system RA, the forecasted RA Adder should be calculated using volume-weighted average of all IOU, CCA and ESP RA-only purchase and sale transactions executed in the fourth quarter of year (n-2), and the first through third quarter of year (n-1) for delivery in year n. The annual RA Adder ($/kW-year) should be the sum of the monthly weighted average of the relevant transactions.

6. For local RA, the RA Adder should be calculated using volume-weighted average of all IOU, CCA and ESP RA-only purchase and sale transactions executed in the years as specified in Attachment A.

7. The calculations should be performed by Energy Division by the first business day in November and should be incorporated into the IOUs' ERRA Forecast applications.

8. Capacity Procurement Mechanism costs should not be incorporated in RA Adder calculations.

9. The dataset requirements for calculating the Adders adopted in D.18-10-019 should be changed to the dataset requirements adopted in this decision.

10. The Energy Division Director should have discretion to modify the proposed data templates, as needed, to collect the data in order to accurately calculate forecast Adders and true them up.

11. The Energy Division Director should be authorized to determine the frequency of data reporting.

12. In the interest of administrative efficiency, we should authorize the Energy Division Director to use the data submitted for compliance purposes or issue supplemental data requests in order to collect sufficient and accurate data for forecasting and truing up Adders.

13. The Commission should adopt the transaction reporting regime set forth in this decision for the purposes of deriving forecasted RA and RPS Adders.

14. For NMP to participate in the stakeholder process in a meaningful and efficient manner, NMPs should be able to have access to data, provided that they agree to a standardized non-disclosure agreement.

15. The Commission should adopt the mechanism proposed in the Working Group One May Report to true up annually the costs and Market Value used in the PCIA calculation, including the following Market Price Benchmarks: the

Energy Index, the Resource Adequacy (RA) Adder and the Renewables Portfolio Standard (RPS) Adder.

16. The true up process should be addressed as part of the annual Energy Resource Recovery Account proceedings.

17. The Commission should confirm the March 20, 2019 ALJ Ruling that all data submitted to Staff by LSEs is entitled to confidentiality protections under D.06-06-066.

18. The Commission should adopt TURN's proposal to give NMPs access to confidential data on a voluntary basis.

19. The true up methodology for the Local RA Value should include all transactions specified in Attachment A.

20. The value of unsold RPS resources should be zero.

21. The true up of Energy Index, RA and RPS Adders should be addressed as part of the annual ERRA Forecast proceedings.

22. 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.

23. The Commission should approve the use of vintage specific billing determinants for PCIA rate design. The specific calculations should be reviewed and approved in each utility's respective 2020 ERRA forecast proceeding.

O R D E R

IT IS ORDERED that:

1. The Commission's Energy Division shall calculate the following values and make them available to interested parties at the beginning of November each year: (1) the Energy Index, (2) the Renewables Portfolio Standard (RPS) Adder, and (3) the Resource Adequacy (RA) Adder.

   a. The Forecast Energy Index shall continue to be calculated using the methodology adopted in D.18-10-019.

   b. The Forecast RPS Adder shall be calculated using the volume weighted average of all investor-owned utility (IOU), Community Choice Aggregator (CCA) and Electric Service Provider (ESP) market transactions using only Portfolio Content Category 1 index-plus contracts executed in the fourth quarter of year (n-2), and the first through third quarter of year (n-1) for delivery in year n, as listed in Table II of Attachment A.

   c. All Load Serving Entities shall provide Staff with 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). Energy Division shall monitor the impact of fixed-price transactions and shall, by the end of 2020, propose a method to include fixed-price contracts in calculating the RPS Adder. We authorize the Energy Division Director to hold workshops or utilize the existing Working Group process to develop the proposal.

   d. For flexible and system RA, the Forecast RA Adder shall be calculated using volume-weighted average of all IOU, CCA and ESP RA-only market transactions executed in the fourth quarter of year (n-2), and the first through third quarter of year (n-1) for delivery in year n, as listed in Table II of Attachment A. The annual Forecast RA Adder ($/kW-year) shall be the sum of the monthly weighted average of the relevant transactions.

e. For local RA, the Forecast RA Adder shall be calculated using volume-weighted average of all IOU, CCA and ESP RA-only market transactions executed in the years listed in Table II of Attachment A.

f. Capacity Procurement Mechanism costs shall not be incorporated in the RA Adder calculations.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall calculate Forecast Renewables Portfolio Standard Value and Forecast Resource Adequacy Value in their respective Energy Resource Recovery Account (ERRA) forecast proceedings by using the price and quantity descriptions listed in Table I and Table II of Attachment B.

3. The Commission's Energy Division shall true up the Renewables Portfolio Standard (RPS) Adder and the Resource Adequacy (RA) Adder and make them available to interested parties at the beginning of November each year. The true up will commence with a true up of the 2019 Power Charge Indifference Adjustment (PCIA) in the 2020 Energy Resource Recovery Account (ERRA) forecast proceedings.

a. The Final RPS Adder shall be used as shown in Table III of Attachment B and shall be calculated using volume weighted average of all investor-owned utility, Community Choice Aggregator and Electric Service Provider market transactions using only Portfolio Content Category 1 index-plus contracts executed in year (n-1), and the first through third quarter of year n for delivery in year n, as listed in Table II of Attachment A.

b. The value of unsold RPS products shall be zero.

c. For flexible and system RA, the Final RA Adder shall be used as shown in Table IV of Attachment B and shall be calculated using volume-weighted average of all IOU, CCA and ESP RA-only market transactions, as listed in Table II of Attachment A.

d. For local RA, the RA Adder shall be used as shown in Table IV of Attachment B and shall be calculated using volume-weighted average of all IOU, CCA and ESP RA-only market transactions executed in years listed in Table II of Attachment A.

e. The value of unsold RA products shall be zero.

f. The year-end over- or under-collection in the vintaged PABA subaccounts related to RA categories for year n shall be included in the vintaged PCIA rate calculation for year (n+1), as part of each utility's ERRA Forecast proceeding.

g. The true up process shall be addressed as part of the annual ERRA Forecast proceeding.

4. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company shall calculate Renewables Portfolio Standard Value True Up and Resource Adequacy Value True Up in their respective Energy Resource Recovery Account (ERRA) proceedings by using the price and quantity descriptions listed in Table III and Table IV of Attachment B.

5. The Commission establishes quarterly transaction reporting requirements for all Load Serving Entities, including Community Choice Aggregators and Electric Service Providers, to ensure that the forecast and true up processes are timely and accurately completed. We authorize the Energy Division Director to reduce the frequency of data reporting for administrative efficiency.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall apply vintage-based billing determinants in their 2020 ERRA Forecast Applications.

7. San Diego Gas & Electric Company (SDG&E) shall give a presentation to Working Group One, providing information on the billing determinants SDG&E uses contrasted with the use of vintaged billing determinants, within 30 days of the issuance of this decision, if it has not already provided the information to interested parties in this proceeding.

8. PG&E, SCE, and SDG&E may each file a Tier 1 Advice Letter within 20 days of the effective date of this decision to implement, if necessary, the provisions of this Decision in their respective tariffs.

9. Rulemaking 17-06-026 remains open.

This order is effective today.

Dated October 10, 2019, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

ATTACHMENT A

Table I. Data Requirements Adopted in D.18-10-019

	System and Flexible RA Adders	**Local RA Adder**	**RPS Adder**
<u>Forecast</u> <u>Adder</u> Dataset	Transactions made during year (n-1) for deliveries in year n (D.18-10-019 at OP 1)	Same datasets as System and Flexible RA (D.18-10-019 appears to have made no distinction for purposes of the datasets.)	Transactions made during the year that is two years prior to the forecast year (year n-2) for delivery in the forecast year (year n). (D.18-10-019 at 119)
<u>Final</u> <u>Adder</u> Dataset	Not explicitly decided by D.18-10-019.	Not explicitly decided by D.18-10-019.	Not explicitly decided by D.18-10-019.

Table II. Data Requirements Adopted for Forecast and Final Adders

	System and Flexible RA Adders	**Local RA Adder**	**RPS Adder**
<u>Forecast</u> <u>Adder</u> Dataset	Transactions executed in Q4 of year (n-2) and Q1-3 of year (n- 1) for delivery in year n	**(n=2020):** Transactions executed in Q4 of year (n-2) and Q1-3 of year (n-1) for delivery in year n **(n=2021):** Transactions executed in year (n-2) and Q1-3 of year (n-1) for delivery in year n **(n=2022) and Beyond:** Transactions executed in year (n-3), year (n-2), and Q1-3 of year (n-1) for delivery in year n	Transactions executed in Q4 of year (n-2) and Q1-3 of year (n- 1) for delivery in year n

<u>Final Adder</u> Dataset	Transactions executed in Q1-4 of (n-1) and Q1-3 of year n for delivery in year n	**(n=2019 and n=2020):** Transactions executed in Q1-4 of year (n-1) and Q1-3 of year n for delivery in year n **(n=2021):** Transactions executed in year (n-2), year (n-1), and Q1-3 of year n for delivery in year n **(n=2022) and Beyond:** Transactions executed in year (n-3), year (n-2), year (n-1), and Q1-3 of year n for delivery in year n	Transactions executed in Q1-4 of year (n-1) and Q1-3 of year n for delivery in year n

Notes:

1. The term "Dataset" refers to the time periods (calendar quarters or calendar years) in which sales or purchases were made (i.e. transactions were executed).

2. "Year n" is the year for which the PCIA calculation is being done. Year n is the forecast year in the forecast Adders and the year being trued up using the final Adders. For example, for the calculations we anticipate making in October 2019 for the 2020 ERRA forecasts, "year n" is 2020 in the forecast Adder calculations but "year n" is 2019 in the true up or final Adder calculations. See D.18-10-019 Ordering Paragraph 5 at 159.

(END OF ATTACHMENT A)

ATTACHMENT B

ATTACHMENT B

Table I: Forecast RPS Value (Price and Quantity)

RPS Product Category	Price	Quantity
Forecast Retained	Forecast RPS Adder, as calculated by Staff	Forecasted IOU RPS compliance need
Actual Sold	Actual prices for transactions up to 45 days prior to ERRA Forecast filing (November update)	Actual volumes of sales up to 45 days prior to ERRA Forecast filing (November update)
Forecast Sold	Forecast RPS Adder	Forecasted sold volume

Table II: Forecast RA Value (Price and Quantity)

	Price ($/kW-year)	Quantity (MW)
Forecast Retained RA	June: Forecast RA Adder published in November of previous year November: Applicable Forecast RA Adder, as calculated by Staff	June: IOU forecasted RA allocations and amounts retained for IOU use[33] November: Final RA allocations and the amounts forecasted retained for IOU use
Actual Sold RA	Actual prices for sales up to 45 days prior to ERRA Forecast filing (November update)	Actual volumes for sales up to 45 days prior to ERRA Forecast filing (November update)
Forecast Sold RA	Applicable Forecast RA Adder, as calculated by Staff	Applicable forecasted sold volumes
Forecast Unsold RA	$0	Applicable forecasted unsold volumes[34]

[33] The amount of RA retained for IOU use is the amount of RA not offered for sale or forecasted to be offered for sale.

Table III: RPS Value True Up (Price and Quantity)

Type of RPS Product	**Price**	**Quantity**
Actual Retained	Final RPS Adder, as calculated by Staff	Volume used for IOU compliance from PCIA-eligible portfolio
Actual Sold	Actual transacted price s	Actual transacted volumes
Actual Unsold	$0	Actual unsold volume

Table IV: RA Value True Up (Price and Quantity)

Type of RA Product	**Price**	**Quantity**
Actual Retained	Applicable Final RA Adder, as calculated by Staff	RA used for compliance and the amounts retained for IOU use
Actual Sold RA	Applicable actual transacted prices	Applicable actual transacted volume
Actual Unsold RA	$0	Quantity offered for sale but not sold or used by IOU

(END OF ATTACHMENT B)

[34] 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.