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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 (Filed June 29, 2017)

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON DATA-RELATED PCIA ISSUES

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On behalf of
California Community Choice Association

October 1, 2021

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Pursuant to Administrative Law Judge ("ALJ") Wang's September 17, 2021 e-mail ruling ("ALJ Ruling"), the California Community Choice Association[1] ("CalCCA") hereby submits these opening comments to convey the urgent need for reform to increase transparency and access to data related to the balancing accounts that underlie Power Charge Indifference Adjustment ("PCIA") rates.

Current data access protocols leave unbundled customers materially less protected from rate changes than bundled customers. Customers of community choice aggregators ("CCAs") remain vulnerable to PCIA changes derived from data to which the CCAs' Reviewing Representatives ("CCA RRs") do not have access, handcuffing their ability to plan for price swings in the medium-to-long term. CalCCA's transparency proposal will address this deficiency by requiring the investor-owned utilities ("IOUs") to provide the *same* limited set of data already provided to the CCA RRs within the Energy Resource Recovery Account

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

("ERRA") proceedings. The IOUs already prepare the detailed Monthly Report data for Energy Division, meaning the burden of providing such data to CCA RRs amounts to adding a handful of recipients to e-mails that already must be sent to Energy Division. Resource-specific details underlying the IOUs' ERRA Forecast proceedings are already provided to CCA RRs during the pendency of a case, but each application is accompanied by a docket-specific Non-Disclosure Agreement ("NDA") that prohibits the use of such data outside the confines of that single application. Since the CalCCA proposal largely would operate *within* the Commission's already onerous confidentiality regime, and would simply allow continued access to data already provided elsewhere, there is no good argument against giving unbundled customers the same protections afforded to bundled customers.

The IOUs center their January comments against the proposal on legal and policy arguments suggesting the Commission need not act to keep CCAs viable. These arguments in this context imply an IOU strategy to harm unbundled customers in the near term in the hope they will respond by returning to bundled service in the long term. Exposing unbundled customers to rate shock must not be endorsed as a strategy to lure them back to bundled service.

With regard to Question 1, a decision in this proceeding can align the data requirements approved last year in the ERRA Forecast proceedings to ensure long-term implementation of those requirements is consistent across the service territories. Further, requiring the data be provided automatically via a Master Data Request ("MDR"), which currently forms part of the regime in Pacific Gas and Electric Company's ("PG&E") service territory, will improve efficiency in these overburdened and expedited proceedings. Lastly, the forecast workpapers from the prior year's forecast case are relevant to analyzing the current year's forecast, as well as ensuring the on-going true-up of that prior year forecast is reasonable and accurate at a high level, and should be routinely provided as part of an MDR. CalCCA recommends action on this latter item within this docket to ensure consistent treatment across utilities and avoid the need for the Commission to address this issue in each of the IOUs' 2022 ERRA Forecast cases, where the CCAs have raised it in testimony in each case.

Giving CCAs the same ability to plan for rate changes the IOUs enjoy will ensure a level playing field and allow all customers to enjoy the benefits of fair competition. These issues are discussed in response to Question 2 from the ALJ Ruling below. In sum, the data the CCAs require year-round in order to protect their customers is as follows:

- The *same* confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission;
- The *same* data and workpapers underlying those Monthly Reports, at the *same* level of granularity, and within the *same* schedule, that is now required to be provided as part of ERRA forecast proceedings in each IOU service territory; and
- Continued access to the *same* workpapers underlying PCIA rates that the IOUs have provided within the prior years' ERRA Forecast proceedings as part of either the November Update or an advice letter implementing the final decision in the ERRA Forecast proceeding.

With regard to Question 3, the tables the ALJ Ruling requested are provided in the body of these comments below, identifying several datasets and categories of data that should be public but are treated inconsistently, and often remain confidential, in different IOUs' ERRA Forecast and Compliance cases. A decision in this case should direct consistency among the IOUs on these data with a goal of maximizing the extent of publicly available information.

For Questions 4-5:

- The Joint IOUs proposal to refund or change the most recent PABA vintage for year-end balances is reasonable, provided it is implemented consistently for all balancing accounts and subaccounts, including PG&E's PCIA Undercollection Balancing Account ("PUBA") Financing Subaccount ("PFS"); and

- If further details are provided in the Joint IOUs' comments, CalCCA anticipates being able to support in reply comments the proposal to credit year-end ERRA balances to PABA to avoided unnecessary ERRA triggers.

Each of these issues is addressed in response to each issue raised in the ALJ Ruling, in turn, below.

I. ERRA DATA ACCESS

The ALJ Ruling states:

> *In comments on the December 2020 scoping memo, CalCCA proposed (i) to require all three IOUs to provide the ERRA data that SCE was required to provide in D.20-12-035, and (ii) require IOUs to provide confidential ERRA Monthly Report data to reviewing representatives who have signed NDAs within 5 business days of filing such report with the Commission.*
>
> *Please comment on each sub-part of this proposal from an operational, legal and/or public policy perspective.*

The Commission intended the data requirements in last year's Southern California Edison Company ("SCE") ERRA Forecast proceeding to streamline access for parties needing such data to meet their evidentiary burden when analyzing and proposing revisions to the forecast year's PCIA rates.[2] The Commission determined that "requiring extensive discovery requests to obtain this information creates additional administrative burdens for the parties to the proceeding as well as Commission staff."[3] The Commission ordered similar data be provided in both PG&E and San Diego Gas and Electric Company's ("SDG&E") ERRA Forecast decisions.[4]

The CalCCA proposals referenced in the ALJ Ruling were intended to ensure the IOUs consistently complied with three different orders issued within three different proceedings that were intended to accomplish the same end. The language of the decisions themselves illustrates

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2 D.20-12-035, Finding of Fact ("FOF") 38.

3 *Id.* at 56 (internal comma deleted).

4 D.20-12-038 at 31-32 and Ordering Paragraph ("OP") 4; D.21-01-017 at OP 6.

the CCAs' concern; PG&E and SCE's orders vary only by one or two words, while SDG&E's requirements are worded in a substantially different manner.[5] In practice, the IOUs' implementation of these directives in this first year of the requirements being in place has been largely consistent despite the difference in language between the orders. Nonetheless, the obligation is long term. Ironing out these differences via an order in this proceeding, *i.e.*, adopting the language used in Ordering Paragraph 8 of D.20-12-035 for all three IOUs as part of a decision in this case, will ensure long-term consistency across the three service territories.

In addition, requiring SCE and SDG&E to follow the MDR approach adopted in PG&E's 2021 ERRA Forecast decision will help to further streamline these unwieldy yet expedited proceedings. The ERRA Forecast cases require parties to process large amounts of data and information in a short timeframe to ensure rates are just and reasonable.[6] In D.20-12-038, the Commission ordered PG&E to provide a response to an MDR "upon the filing" of each future ERRA proceeding that includes the ERRA Monthly Report data.[7] The PG&E process avoids the need to submit data requests, saving precious weeks for parties that already have insufficient time to litigate these cases.

Lastly, beyond these process improvements, the IOUs should be required to allow non-docket-specific access to the detailed workpapers used to derive the annual PCIA rate updates in ERRA Forecast proceedings. Resource-specific details underlying the IOUs' ERRA Forecast proceedings are already provided to CCA RRs during the pendency of a case, but each application is accompanied by a docket-specific NDA that Reviewing Representatives must sign

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5 *Compare* D.20-12-038 at 31-32 and OP 4 *to* D.21-01-017 at OP 6 *to* D.20-12-035 at OP 8.

6 *See, e.g.,* R.17-06-026, *California Community Choice Association's Comments in Response to E-Mail Ruling Requesting Comments on Market Price Benchmark Issue Date*, pp. 7-19 (Sep. 13, 2021).

7 D.20-12-038 at OP 4.

and which prohibits the use of such data outside the confines of that single application. In each of the IOU's recent ERRA Forecast cases, the CCAs have sought the documentation from the previous case supporting the composition of current vintage PCIA rates (for year n) in the forecast proceeding setting new PCIA rates (for year n+1). Review of the documentation supporting the previously forecasted Indifference Amount and the PCIA rates is required to determine the extent to which deviations from the previous forecast are causing the PABA true-up balance or are driving increases in newly forecasted PCIA rates.

There is great value in comparing newly forecasted data to prior forecasts and actual data. One of the first things a responsible analyst will do in assessing a forecast for one year is to compare it to the forecast from last year. The comparison is a helpful analytical tool to see how resources are utilized from one year to the next and how they are accounted for from one year to the next. For example, this technique revealed a $24 million error in SCE's 2022 ERRA Forecast case, where units that had been assigned resource adequacy value in the 2021 forecast were inadvertently not assigned resource adequacy value in the 2022 forecast.[8]

CCAs also utilize their testimony in ERRA Forecast proceedings to present high-level analysis of factors driving the PABA balance in each year's application.[9] In fact, PG&E's testimony in its proceeding provides a similar analysis, but the utility has sought to prevent the CCAs from conducting their own analysis to confirm its accuracy.[10] The CCAs simply wish to

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[8] A.21-06-003, *Prepared Direct Testimony of Brian Dickman on Behalf of SoCal CCAs in Southern California Edison Company's 2022 ERRA Forecast Proceeding*, pp. 12-13 (Sep. 27, 2021) ("SoCal CCAs Testimony").

[9] A.21-06-001, *Motion to Compel Discovery of the Joint CCAs*, pp. 1-3 (Aug. 31, 2021) ("Motion to Compel").

[10] *Id.*

have access to the same data to write the CCAs' testimony in these cases to which the utilities had access when they wrote their own testimony.

The IOUs have provided these data to CCAs in previous years,[11] and SCE provides them as part of its workpapers in its testimony.[12] PG&E provided this same data last year but has refused this year after a nearly identical discovery dispute occurred.[13] SDG&E simply refused, without initially offering an objection, to provide these data supporting current PCIA rates in its discovery responses and eventually won on the issue of keeping its application opaque via a short e-mail ruling to a Motion to Compel that provided little reasoning for its conclusion. Making that ruling more bewildering, the CCA RRs *already were provided access* to the requested data in the prior year's forecast but cannot use them again here, without requesting it anew from the IOUs, under the terms of the NDA in that previous case.[14]

A comparison of prior PCIA forecasts to actual PABA results can reveal problematic trends that should be addressed. It can also identify errors in PABA accounting. In a bit of irony, after denying CCAs access to its 2021 PCIA workpapers which would have enabled verification of the 2021 PABA balance included in its 2022 ERRA Forecast application, SDG&E disclosed that it had erroneously relied on the 2020 ERRA Forecast revenue rather than the 2021 ERRA Forecast revenue to project the 2021 PABA included in the current application.[15] The error understated the 2021 PABA balance by *nearly $100 million*.

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[11] *Id.*

[12] SoCal CCAs Testimony at 20-25.

[13] Motion to Compel at 1-3.

[14] *Id.*

[15] A.21-04-010, E-mail form SDG&E Counsel to Service List (Sep. 16, 2021) (stating "SDG&E has discovered an error with respect to the Portfolio Allocation Balancing Account (PABA) revenue requirement forecast set forth in the 2021 ERRA Forecast Application (A.21-04-010). Specifically,

The Commission made long strides towards transparency in last year's ERRA Forecast proceedings, providing half of the data necessary to understand current PABA balances. Continuing to shed light on these arcane proceedings by providing the other half of that data is a crucial next step. That next step should be taken as part of a decision in this case, providing consistent treatment between IOUs, or within the ERRA forecast proceedings themselves, where the CCAs have made the same ask in each of the three proceedings.

II. PCIA FORECASTING DATA ACCESS

In D.18-10-019, the Commission adopted a PCIA cap to avoid volatility and promote certainty and stability for *all* customers: "We find that the potential for volatility supports adoption of a PCIA cap in this decision. Such a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection.[16] Similarly, "[w]e affirm that a cap protects against volatility in the PCIA."[17] As formally set forth in Finding of Fact 18: "A PCIA cap will limit the change of the PCIA from one year to the next. A cap that limits the change of the PCIA from one year to the next promotes certainty and stability for all customers within a reasonable planning horizon."[18] In D.21-05-030, the Commission recognized that the cap it had adopted only exacerbated volatility and removed it.[19]

SDG&E has discovered an error in its billed revenue forecast that impacted the projected 2021 PABA Year End balance set forth in the Application. The forecast model used in the Application inadvertently used the 2020 authorized ERRA Revenue Forecast instead of the 2021 ERRA Revenue Forecast. This resulted in an overstatement of forecasted billed revenue. After correcting this error and updating for actuals through August 2021, SDG&E now forecasts the 2021 PABA Year End balance (excluding adders for the 2020 ERRA Trigger Adjustment and CAPBA Trigger Adjustment) to be an over collection of $61.8M. SDG&E's Application had forecasted the 2021 PABA Year End Balance (excluding adders) to be an over collection of $159.6M.").

[16] D.18-10-019 at 85.

[17] *Id.* at 86.

[18] *Id.* at FOF 18.

[19] D.20-05-030 at 6-8, FOF 1, Conclusion of Law ("COL") 1, and OP 1.

While the cap no longer exists, the potential for "extreme PCIA price spikes," "bill impacts", and "volatility," and the resulting need for "certainty and stability for *all* customers within a reasonable planning horizon," still exists. In PG&E's 2020 ERRA Forecast application, PG&E predicted a $447.3 million undercollection in the 2019 PABA until the day before hearing when a $224 million error related to the imputed RA value was discovered. The resulting modification changed the projected $447.3 million undercollection to a $223.5 million undercollection.[20] Three months later, however, PG&E's 2019 PABA undercollection grew almost $400 million to reach $611.4 million.[21] These fluctuations had an enormous impact on the rates CCA customers would pay, moving the PCIA by approximately $0.005/kWh (or *15 percent*) in three months.

Without an effective cap to control PCIA rates, CCA customers must rely on forecasting to plan and manage rate spikes for their customers, and the key to reliable, real-time forecasting is data access and transparency. CCAs must be able to see how, but more importantly why, the balances feeding the PCIA are changing. However, the limited access to data provided in the IOUs' Monthly Reports leave unbundled customers materially less protected from rate changes than bundled customers and must be addressed. CalCCA's proposal makes small, incremental adjustments to how data is provided that can address these issues *within* the Commission's existing confidentiality frameworks.

The ALJ Ruling states:

> *In comments on the December 2020 scoping memo, CalCCA proposed to require the IOUs to provide year-round access to key cost and revenue data, including (1) confidential versions of monthly reports for each month of the*

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[20] A.19-06-001, 1 Tr. 29:2-30:24 (PG&E – Keller); Exh. PG&E-4 at Table 14-3 (corrected – redline version).

[21] A.19-06-001, *Pacific Gas and Electric Company Update to Prepared Testimony*, p. 8, line 21 (Nov. 8, 2019).

year, when they are provided to the Commission, and (2) data and workpapers underlying these reports, at the same level of granularity and on the same schedule as required for future ERRA proceedings. CalCCA proposed to require IOUs provide year-round access to this data through Year-Round NDAs that would allow reviewing representatives to use the data provided in the ERRA Monthly Reports outside the context ERRA Forecast proceedings for the limited purpose of creating PCIA rate forecasts that are based on, but do not disclose, confidential data, and can be shared with CCA decision-makers to allow them to plan for future rate changes.

A. Making Confidential ERRA Monthly Reports Data Available to CCAs Outside of the ERRA proceedings Protects *All* Customers.

The ALJ Ruling then asks:

a. *Why is it in the public interest to make confidential ERRA Monthly Reports data available to CCAs outside of the ERRA proceedings?*

Answering this question requires understanding (1) the impacts of the PABA balance on PCIA rates and (2) why there is no good argument against data transparency that is intended to protect customers.

1. The PABA Balance Drives Variability in PCIA Rates.

CCAs are currently responsible for providing the energy resources needed to serve over one-half of energy usage in the IOUs' service territories and are playing a critical role in achieving California's renewable energy and reliability goals. Any actions that help CCAs better plan their energy procurement is inherently in the public interest to help California achieve its goals.

PCIA rates are a major component of the generation rates unbundled customers pay, currently as high as $0.047/kWh for residential customers within the three IOUs' service territories and can affect or limit a CCA's procurement choices. The PCIA materially affects the rates CCAs charge their customers and requires the CCAs to keep tabs at all times on where the PCIA rate is heading. CCAs may need to "absorb" spikes in the PCIA by reducing the generation rates they charge for their own procured power in order to protect their customers from a large increase. This type of consumer protection requires planning, which can take the form of reserve policies that act similar to balancing accounts the IOUs employ.

Currently, unbundled CCA customers cannot understand, plan for or protect customers from rate changes to the same extent the utilities are able to do so. At the heart of the issue is the tension created by the PCIA framework adopted in Decisions 18-10-019 and 19-10-001. Those decisions created a long-term exit fee that changes each year, will exist for decades to come and, most importantly for the instant discussion, is based on the cost and market value of the IOUs' generation portfolios. That is, the PCIA generation rate that is charged to *one* load-serving entity's ("LSE's") customers is based on *another* LSE's data. The IOUs have more information about where the PCIA is going because they hold all the data; CCA RRs have only limited, confidential information available during the six months in which the ERRA forecast proceedings are being litigated. This mismatch leaves unbundled customers less protected than bundled customers from rate changes – especially with no PCIA cap.

Ensuring the measures CCAs take are sufficient to protect customers from rate shock requires a deep understanding of the factors driving PCIA rates during all twelve months of the year. This is because two factors influence PCIA rates: (1) the forecasted Indifference Amount for the following year and (2) changes to the PABA balance that result from an on-going true-up of forecasted versus actual rates. The IOUs' ERRA proceedings calculate the PCIA rate for the next calendar year from these two values, and currently no mid- or long-term forecast for this rate is provided. In their January comments, the IOUs completely ignore the importance of the second component of setting PCIA rates, stating "the data provided in the IOUs' Monthly

Reports are of little use in forecasting future PCIA rates."[22] This statement could not be further from the truth.

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. Decision 18-10-019 approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and departing load customers. This true-up now occurs via the PABA, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues an IOU realizes during the year related to its PCIA-eligible resource portfolio. Any resulting over- or under-collection in the PABA projected to occur by the end of the year is added to the Indifference Amount to establish the PCIA revenue requirement and determine PCIA rates effective in the forecast year approved as part of each ERRA Forecast proceeding.

Since its inception, the PABA has been a major contributor to the total PCIA revenue requirement and has proven to be unpredictable, fluctuating by hundreds of millions of dollars. For example, in 2020 PG&E began the year with a PABA balance of just over $700 million, which increased to just under $800 million by the time PG&E's ERRA Forecast application was filed in April.[23] By July, the balance was nearly $950 million.[24] However, the high prices for brown power during the August and September 2020 heatwaves caused that balance to drop to approximately $460 million by the November Update (the balanced ultimately used to set PCIA

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[22] A.17-06-026, *Joint Reply Comments of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902 E) and Pacific Gas and Electric Company (U 39 E) to Commissioner's Amended Scoping Memo and Ruling*, pp. 7-8 (Feb. 5, 2021) ("Joint IOU Reply Comments").

[23] A.20-07-002, Exh. JCCAs-1-C at 23:19-20 and 27:4-28:7.

[24] *Id.* at 24:1-7.

rates).[25] In SCE's service territory, SCE began the year 2020 with a PABA balance of $537 million, which rose to $637 million by May, rose again to $769 million at the end of July 2020, and fell to approximately $500 million in December due to the August heat wave.[26]

Factors driving the initial PABA increases included decreased customer revenues from the COVID epidemic, a drop in the market value of non-RPS energy, and RPS energy, and, to a lesser extent, lower RA value and an increase in portfolio costs.[27] Later-year PABA changes were tied to the brown power prices that spiked during the late-summer heatwaves. This year, the key factor driving PCIA rates in PG&E's service territory, for example, appears to be brown power rates, although the utility has refused to provide the same data needed to confirm this analysis that it provided last year (as discussed *supra*).[28] Prudent LSEs will keep tabs on these components, and especially brown power prices, in order to plan *in the short term* for *uncapped* PCIA changes that will occur on January 1. The problem is there is no way for non-utility LSEs to plan for the medium or long-term.

CalCCA's proposal will provide such information year-round. Understanding PABA drivers year-round allows CCAs to know which elements of the market are affecting PABA balances every month of the year. Volumetric data (*i.e.,* kWh, MWh and MW) underlying collected IOU customer revenues, generation revenues, and RPS energy and RA capacity sales

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25 *See* A.20-07-002, Exh. PGE-6-C at Table 14 (PG&E's November Update (filed in November 2020 for 2021 rates) included a PABA balance of $461.7 million (with RF&U, but before transferring the year-end ERRA over). That is the year-end PABA balance that went into 2021 PCIA rates.).

26 A.20-07-004, Exh. CCA-01 at 14:1 to 16:2; *see* SCE Advice Letter 4375-E (Dec. 21, 2020) (Table 5 of Appendix A in SCE's November Update included a PABA balance of $493.9 million (with FF&U, but before transferring year end ERRA). However, in Advice Letter 4375-E, SCE updated its year-end balances, with a final PABA balance for 2021 PCIA rates of $506.2 million).

27 *See, e.g.,* A.20-07-002, Exh. JCCAs-1-C at 27:4-30:2.

28 However, as discussed above, PG&E refused to give the CCAs access to the data necessary to perform this type of analysis, and the Commission has not ruled on the CCAs' Motion to Compel. Motion to Compel at 1-3.

illuminate not only which way the PABA balance is moving but most importantly why it is moving in that direction. However, nearly all of this data is *solely in the IOUs' possession*. Given both the variability and importance of this final balance, it is essential that the IOUs routinely provide clear and consistent data regarding the PABA balance and its drivers.

The suggestion in the IOUs' reply comments in January that parties can "get an indication of the [PABA] balance" from the public version of these Monthly Reports is shallow.[29] As can be seen in the excerpt from the public version of SCE's November 2020 monthly report below, the publicly available reports generally contain two lines of data: total revenue and total costs.

Southern California Edison Company
Portfolio Allocation Balancing Account (PABA)
November 2020
Recorded ($000)

DESCRIPTION	January	February	March	April	May	June	July	August	September	October	November	December	Total
Beginning Balance	538,526	522,393	558,315	599,910	671,408	673,118	744,027	769,114	673,318	685,573	606,527	-	538,526
Total Net Revenues	(67,016)	(40,506)	(57,453)	(64,156)	(146,148)	(168,389)	(246,678)	(192,655)	(167,168)	(168,058)	(70,374)	-	(1,388,601)
Total PABA Costs	72,759	81,591	98,295	134,892	147,310	239,496	244,790	96,320	179,354	88,947	48,582	-	781,384
Total PABA Activity	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest	767	715	752	762	549	165	115	84	68	65	55	-	4,097
Total PABA Ending Balance	545,037	564,193	599,910	671,408	673,118	744,027	769,114	673,318	685,573	606,527	584,790	-	584,790

Those lines include no differentiation based on products or provide any indication of the volumes influencing those revenues and costs. One cannot discern if the PABA balance went up due to decreased retail sales, costs that were higher than expected, or CAISO revenues that were down compared to the forecast. These summary-level historical balances provide zero indication of the fundamentals causing the balances or the direction in which the balances might head in the future.

The IOUs argued in January that "CalCCA fails to identify the specific information that it believes CCAs must access in order to estimate future PCIA rates."[30] To be clear, the CCAs

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[29] Joint IOU Reply Comments at 14.

[30] *Id.* at 7.

simply seek the *same data* the decisions from last year's ERRA Forecast cases now require the IOUs to provide to CCAs within those cases, as well as the ability to use the *same workpapers* provided in prior years' forecast cases underlying current PCIA rates. In sum, the CalCCA proposal requests:

- The *same* confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission;
- The *same* data and workpapers underlying those Monthly Reports, at the *same* level of granularity, and within the *same* schedule, that is now required to be provided as part of the ERRA forecast proceedings in each IOU service territory; and
- Continued access to the *same* workpapers underlying PCIA rates that the IOUs have provided within the prior years' ERRA Forecast proceedings as part of either the November Update or an advice letter implementing the final decision in the ERRA Forecast proceeding.

These data reveal trends in prior PCIA rates, the fundamentals underlying current PCIA rates, and the fundamentals driving the current PABA balance, giving the CCAs increased ability to compile medium and long-term forecasts to protect unbundled customers just as bundled customers are currently protected.

2. There is No Good Argument Against Transparency to Protect Customers.

The fact the CCAs seek the same data already provided to their Reviewing Representatives in other contexts also defeats the IOUs' argument that granting such access would "provide CCAs with valuable (and improper) insight into IOU contract pricing and other market-sensitive contract terms, the provision of which would be detrimental to bundled service customers."[31] The *same* Reviewing Representatives would have access to contract pricing and market-sensitive contract terms that already have access within the ERRA proceedings.

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[31] *Id.* at 9-11.

Granting unbundled customers access to the *same* data via their Reviewing Representatives to which bundled customers' representatives already have access enables CCAs to provide the *same* protection from rate volatility as the IOUs can currently provide to their customers. The provision of data is not a zero-sum game, where supporting unbundled customers' ability to withstand rate changes somehow imperils bundled customers.

Rather than protecting bundled customers, the IOUs' true aim seems to be to hold onto data access as a competitive advantage. The IOUs' January comments include their oft-repeated argument that "[t]he Commission is not obligated to facilitate CCAs' business planning and decision-making activities."[32] This argument in this context implies the IOUs see withholding data as a winning strategy, where harming unbundled customers in the near term via exposure to volatile PCIA rates could result in those customers returning to bundled service in the long term. The Commission should not endorse such a strategy. Giving CCAs the same ability to plan for rate changes the IOUs enjoy will ensure a level playing field and allow *all* customers to enjoy the benefits of fair competition.

Lastly, the IOUs' January comments include a number of legal arguments citing to Public Utilities Code §454.5(g), D.06-06-066, and the Commission's rules of discovery, making too much of the fact the requested data would be provided outside of a Commission proceeding.[33] First, the goal of CalCCA's proposal is to work *within* the Commission's existing confidentiality framework as much as possible, rendering many of the extensive arguments from the IOUs moot. For example, SCE cites to a litany of decisions as establishing its requirement to submit the Monthly Report: D.02-12-074, D.03-12-062, D.04-12-048, D.07-04-020, D.18-10-019, and

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32 *Id.* at 10.

33 *Id.* at 9-11.

D.20-12-035. To the extent the IOUs desire docket-specific NDAs for access to the Monthly Report, the agreements can be tied to one or more of these cases since those proceedings establish an on-going compliance obligation.

More relevant, however, none of the legal precedent the IOUs cite stands for the proposition that the Commission is prevented from creating carve-outs to its existing confidentiality regime for special circumstances. Section 454.5(g) requires the Commission to 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 …."[34] No part of that statute, which was adopted prior to the Commission implementation of the current PCIA framework, prevents the Commission from establishing procedures for the provision of data outside of an open proceeding. No part of that statute prevents the Commission establishing "appropriate procedures" to address issues that implicate the public interest that have arisen after the statute was implemented.

In fact, providing access to the confidential data underlying the Monthly Reports follows part of the policy underlying the obligation to file the Monthly Reports in the first place: providing stakeholders with the data necessary to understand the trajectory of the IOUs' generation balances in order to predict large swings in rates. The obligation stems from the 2002 Commission decision establishing the ERRA trigger. As D.02-12-074 describes, PG&E had sought "authority to automatically transfer overcollection amounts" in order to bring any "undercollection in the ERRA to the 4 percent level."[35] PG&E also "proposed implementing

[34] Cal. Pub. Util. Code §454.5(g).

[35] D.02-12-074 at 60.

automatic rate changes requests when the Commission does not act in a timely manner upon an expedited trigger application."[36]

The Commission adopted the trigger proposal but required a report to be filed "to give the Commission the opportunity to anticipate when an expedited trigger application might be filed by any utility,"[37] recognizing that PG&E desired the trigger applications to be approved quickly so that rates could change quickly. That is, one part of the purpose of the reports is to keep the Commission and stakeholders informed of changes in the utilities' balancing accounts that could cause triggers—and the resulting large swing in rates—to occur. Here, the CCAs similarly seek data underlying the PABA balances to allow them to forecast large swings in PCIA rates.

Neither D.06-06-066 and its progeny, nor the Commission's rules prevent the Commission from creating carve-outs to its existing confidentiality framework to address new market circumstances that warrant them. The Commission certainly has done so before. In D.11-07-038 the Commission created an exception for the Energy Producers and Users Coalition to gain access to confidential materials as a non-market participant in rate cases but stated the organization would be a market participant for utility procurement proceedings.[38] In a December 2017 ruling in this proceeding, the Assigned Commissioner and ALJ approved a Phase 1 NDA that was negotiated by CCAs and IOUs consistent with the ALJ's directive.[39] While restrictive, that NDA eased the restrictions on Reviewing Representatives to allow a measure of greater

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[36] D.02-12-074 at 60.

[37] *Id*. at OP 19.

[38] D.11-07-028 at 4.

[39] R.17-06-026, *Assigned Commissioner and Assigned Administrative Law Judge Ruling Granting Relief Sought In December 8, 2017 Supplemental Joint Report On Data Issues*, p. 1 (Dec. 20, 2017).

flexibility than the Model Protective Order provides.[40] Namely, Section 2.H.2 permitted employees of market participants (including the IOUs) to gain access to confidential information subject to strict limitations on the role of that employee.[41]

As D.20-12-035 recognizes, "[g]ranting independent consultants access to confidential market sensitive information, under appropriate non-disclosure agreements, is a reasonable means of allowing market participants to review confidential versions of ERRA/PABA/PUBA reports."[42] There is no reasonable argument – legal, policy or otherwise – against transparency when sufficient protections are in place.

B. Access to Confidential ERRA Monthly Reports Should be Limited.

The ALJ Ruling asks:

b. *Which types of stakeholders besides CCAs should have access to confidential ERRA Monthly Reports for the purpose of creating PCIA rate forecasts?*

The IOUs' concerns about widespread dissemination of market-sensitive materials are valid, and access to the Monthly Reports should be limited. Only representatives of organizations representing customers that pay the PCIA should have access to this data and only to the extent those representatives are willing to sign an NDA.

C. A Year-Round NDA Can Provide the Same Protection as Docket-Specific NDAs.

The ALJ Ruling asks:

c. *Can a Year-Round NDA reasonably prevent CCAs or other stakeholders from using ERRA Monthly Reports data for non-approved purposes?*

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[40] R.17-06-026, *Supplemental Joint Report on Results of Meet and Confer Regarding Data Issues*, Attachments A and B (Dec. 8, 2017).

[41] *Id.* at Attachment B.

[42] D.20-12-035 at COL 5.

CalCCA's proposal is to "require the IOUs *work with parties* to this proceeding to develop NDAs that are non-docket specific, *i.e.*, NDAs that would apply to year-round provision of confidential data."[43] Those NDAs would include the *same* protections that currently exist in the model NDA approved in D.08-04-023:

- IOUs' ability to challenge a Reviewing Representative and refuse to disclose data to particular individuals the IOUs do not believe qualify as Reviewing Representatives;

- Limitations on the use of the data, modified in a manner such as the following: "Reviewing Representatives shall use Protected Materials solely for the purpose of participating in this proceeding and more generally for use in PCIA forecasting, on behalf of Market Participants and Non-Market Participants, provided that any confidential data remains protected from disclosure within the forecasting model and subject to the ongoing conditions of the NDA.";

- Proper marking of documents, *e.g.*, designation of "protected materials" and redaction of confidential data where appropriate;

- Limitations on the ability to make copies of protected materials;

- Liability for unauthorized disclosure; and

- Notice provisions regarding requests to disclose protected materials.

Moreover, to avoid perpetual obligations to provide data to certain individuals, the NDAs themselves could be annual in their effect. That is, Reviewing Representatives could be required to execute a new NDA each year in order to gain or continue to have access to protected materials. This protocol would allow the IOUs to re-evaluate Reviewing Representatives on an annual basis, including the ability to require the Reviewing Representatives to destroy materials

[43] R.17-06-026, *California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 22 (Jan. 22, 2021) ("CalCCA Opening Comments").

once a person is no longer a Reviewing Representative. These and other details of the NDA language can be worked out via a meet-and-confer process and/or the Advice Letter process.

Lastly, it is important to note that current CCA RRs for the Joint CCAs understand, take seriously and act upon the fact that D.11-07-028 requires an ethics wall incorporating the following standards:

- When reviewing or discussing any market sensitive data, the Reviewing Representative and those working with them shall employ all reasonable steps to ensure a physical separation from firm personnel who are not authorized Reviewing Representatives;
- The Reviewing Representative shall be responsible for informing all firm personnel about the existence and terms of the Commission's confidentiality rules, and in particular the prohibition against sharing market sensitive information with Market Participants; and
- The Reviewing Representative shall take all reasonable steps necessary to ensure that market sensitive information and files, including electronic files, are not accessible to firm personnel who are not authorized Reviewing Representatives.

Personnel at NewGen Strategies and Solutions, LLC and Keyes & Fox LLP, for example, that are Reviewing Representatives have all been trained on the D.11-07-028 criteria, including the fact that when reviewing or discussing market sensitive data, reasonable measures should be taken to physically separate from non-CCA RRs. CCA RRs either work remotely or have access to enclosed offices and meeting rooms where sensitive information may be discussed. CCA RRs review the D.11-07-028 standards with their colleagues periodically, such as discussing a slide, similar to the one in Attachment A to these comments, in regularly-scheduled practice-wide conference calls. The CCA RRs have established secure electronic file storage locations with restricted access. Permission to access file storage locations must be affirmatively granted to current NDA signatories. These protocols would continue with regard to any data provided under the NDA contemplated in CalCCA's proposal.

These data and any PCIA modeling derived from them would not be shared outside of existing attorney-client and other contractual relationships with CCA clients. The model would not reveal any confidential information since doing so would be a breach of the NDA, exposing the CCA RRs to substantial liability. The CCA RRs also could share the model with Commission staff upon request to allow the Commission to verify confidential information is not being revealed.

D. Any Alternative Must Provide Equal Access to Data.

d. Is there an alternative to CalCCA's proposal that would enable CCAs to create PCIA forecasts year-round?

Reasonable alternatives may exist. However, no alternative should be adopted that prevents the CCAs from accessing the same data already supplied to Reviewing Representatives within ERRA Forecast proceedings: namely, detailed data underlying the Monthly Reports and workpapers relied on to forecast PCIA rates.

III. CONFIDENTIAL DATA CONSISTENCY

In comments on the December 2020 scoping memo, CalCCA proposed that the Commission require consistency across IOUs regarding what information is considered confidential.

a. Proponents of this proposal should provide a chart showing which datasets or categories of data should be public and which should be confidential. The chart should indicate the current public/confidential designation of each IOU. The chart should reference the confidentiality matrices adopted in D.06-06-066 (as amended), as applicable.

Tables 1 and 2 identify several datasets and categories of data that should be public but are treated inconsistently, and often remain confidential, in different IOUs' ERRA Forecast and Compliance cases. Tables 1 and 2 are drawn from the CCAs' experience participating in the IOUs' ERRA Forecast and Compliance cases. As such, the information provided may not be a comprehensive list of all data issues; rather, Tables 1 and 2 identify incorrect or inconsistent application of the Commission's confidentiality standards pertaining to data requested and reviewed by the CCA RRs in past ERRA cases.

Table 1 primarily illustrates inconsistent treatment of aggregate data in the IOU ERRA proceedings. Each of these data categories should be made public according to the D.06-06-066 confidentiality matrix, but treatment varies among IOUs. Access to the data categories contained in Table 1 is necessary to interpret and understand the component parts underlying PCIA rates determined in the ERRA proceedings.

Table 1: Inconsistency in ERRA Forecast and Compliance Proceedings

ERRA Proceeding	Data Category	D.06-06-066 Matrix	PG&E	SCE	SDG&E
Forecast	PCIA Portfolio Cost by Vintage	Section II.B.8	Public	Public	Confidential
Forecast	GRC Revenue Requirement by Vintage	Section III.A	Public	Public	Confidential
Forecast	Total PCIA/PABA Revenue Requirement by Vintage	Section III.A & III.B	Public	Public	Confidential
Forecast	Total PCIA/PABA Revenue Requirement by Customer Class and by Vintage	Section III.A & III.B	Public	Public	Confidential
Forecast	Sales Volume by Customer Class and by Vintage (i.e. PCIA rate billing determinants by vintage)	Section V.G	Public	Public (Note 2)	Confidential
Forecast	Renewable Resource Contract Details (cost, energy, capacity, etc.)	Section IV.I	Public	Confidential	Confidential
Forecast	Aggregated Annual Capacity and Energy Data from All Resources (Gross output)	Section IV.E & IV.F	Confidential	Confidential	Public

ERRA Proceeding	Data Category	D.06-06-066 Matrix	PG&E	SCE	SDG&E
Forecast and Compliance (Note 1)	Individual Resource Attribute Identification (See Table 2 for additional detail)	Section VII.B	Public	Confidential	Public

Note 1: PG&E and SDG&E ERRA Forecast workpapers provide some resource identifiers on a non-confidential basis, but not all resource information is provided. SCE generally keeps individual resource information confidential but may disclose publicly in part.

Note 2: SCE makes public the sales volume by customer class and by vintage, except for the latest vintage which, if public, would allow a user to derive bundled customer sales volume. PG&E publicly discloses sales volume by customer class for all vintages, including bundled customers.

Part of the CCAs' review of annual PCIA rate changes has been to confirm that individual IOU resources are correctly assigned to the various Commission-approved cost recovery mechanisms (*e.g.*, PCIA, CAM, CTC, etc.). Descriptive attributes unique to individual resources – such as the resource identifiers, counterparty, contract dates, etc. – are generally considered to be publicly available. Table 2 identifies resource attributes that CCAs have requested or reviewed in the ERRA proceedings for each IOU. Here again, the CCAs have found incorrect and inconsistent application of the confidentiality protocols in D.06-06-066 (and in some cases have requested data not specifically addressed by the D.06-06-066 matrices). In some cases, the treatment of resource specific information has been inconsistent within a filing.

Table 2: Individual Resource Attribute Identification

Data	D.06-06-066 Matrix	PG&E	SCE	SDG&E
Resource name	Section VII.B	Public	Confidential	Public
Resource ID (CAISO)	NA	Public	Confidential	Public

Data	D.06-06-066 Matrix	PG&E	SCE	SDG&E
Internal Resource Identifier	NA	Public	Confidential	Public
Resource Technology	NA	Public	Confidential	Public
Location	Section VII.B	Public	Not Provided	Public
Contract Type	Section VII.B	Public	Confidential	Public
Counterparty	Section VII.B	Public	Not Provided	Public
Contract Execution Date	Section VII.B	Public	Confidential	Public
Commercial Operation Date	Section VII.B	Public	Not Provided	Public
Contract Expiration Date	Section VII.B	Public	Confidential	Public
Nameplate Capacity	Section VII.B	Public	Confidential	Public
CPUC Authorization	NA	Public	Not Provided	Public
Cost Recovery Mechanism	NA	Public	Confidential	Public
PCIA Vintage	NA	Public	Confidential	Public
RPS Eligibility	NA	Public	Confidential	Public
RA Type	NA	Confidential	Confidential	Public
Net Qualifying Capacity	NA	Confidential	Confidential	Public
Historical MWh	Section X.G, X.H, X.I	Public	Confidential	Public

Notes:

1. Section VII of the D.06-06-066 IOU matrix addresses bilateral contracts, and information for utility retained generation should be treated in a similar manner

2. SCE treats resource attributes as confidential in its ERRA Forecast cases, and is inconsistent in its treatment in ERRA Compliance cases (sometimes confidential, sometimes public)

The increases in transparency discussed throughout these comments will support more efficient implementation of PCIA issues within ERRA proceedings. In addition, the Commission can ease parties' review of the proceedings, and reduce the need for discovery and other administrative burdens, by requiring the utilities to make consistent their designation of data sets as either confidential or public.

A particularly egregious example of this inconsistency is that SDG&E considers its total portfolio costs to be confidential, whereas PG&E and SCE reasonably provide this data as public. Additional examples of inconsistent confidentiality designations include:

- PG&E and SCE make public vintaged UOG General Rate Case (GRC) costs, procurement costs, and total vintage costs (i.e. the sum of UOG GRC costs + procurement costs). SDG&E provides neither procurement costs nor total costs; they provide only total UOG GRC costs.
- PG&E and SCE make public the total system sales, and sales within each vintage, used to derive the PCIA rates, with sales volumes shown as annual kWh by class; SDG&E does not.
- PG&E and SDG&E make the list of PCIA-eligible generation resources by vintage available publicly; SCE does not.

CalCCA recommends that the Commission direct consistency among IOUs on these issues with a goal of maximizing the extent of publicly available information to ensure ratemaking is as transparent as possible.

IV. YEAR-END BALANCES AND CREDITING CUSTOMERS

The ALJ Ruling states:

> *In comments on the December 2020 scoping memo, the Joint IOUs proposed that the Commission direct the IOUs to transfer ERRA and PUBA/CAPBA year-end balances to the corresponding subaccount of PABA, consistent with ratemaking in SCE's 2020 and 2021 ERRA forecast proceedings, for every year moving forward.*

a. *Please comment on this proposal from an operational, legal and/or public policy perspective.*

As noted in CalCCA's January comments, a common methodology has emerged to some degree via recent ERRA and PUBA/CAPBA trigger proceedings to transfer ERRA and PUBA/CAPBA year-end balances to the corresponding subaccount of PABA. That common approach is the one referenced in the ALJ Ruling, *i.e.*, to return the end-of-year balance going forward via the most recent vintage.[44] Because customer vintages are determined on a July to June schedule, the proposal to transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing on or after July 1 are credited (or charged) for the ERRA balance accruing during the year of their departure.[45] Customers that depart in the first half of a year in which an overcollection accrues, however, are unlikely to receive any credit for refunds they are owed (with the inverse being true in the case of an undercollection). The Commission adopted this approach for the ERRA trigger undercollections in SCE's service territory (A.18-11-009),[46] and with regard to CAPBA financing in SDG&E's service territory

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44 A.20-07-002, Exh. PG&E-1 at 19-7:6-15 and 19-4:22-25. PG&E also proposed to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage. A.20-07-002, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, pp. 5, 12-13, 18, 21 (July 1, 2020).

45 A.20-07-002, Exh. JCCAs-1 at 37:20 to 38:3.

46 *See* D.19-01-045 at OP 2 (stating "Southern California Edison Company shall collect the Energy Resource Recovery Account undercollection through a pro-rata apportionment of the costs to 2018 SCE bundled service customers, including 2018 and 2019 vintage departing load customers, utilizing bundled service allocation factors established in D.18-11-027, and using the Power Charge Indifference Adjustment as the rate recovery vehicle for the undercollection amount.").

(A.20-07-009).[47] It also adopted a similar but inconsistent approach in D.20-12-038 for PG&E, as discussed below.

CalCCA continues to support the Joint IOUs' proposal, which most closely aligns cost responsibility with cost causation given the challenges that come from the mismatch between resource vintaging and customer vintaging,[48] but it must be applied uniformly. Transferring the amount due customers who were bundled customers at the time the cost was incurred to the recent PABA vintage(s) ensures that all customers – bundled or recently departed – receive credit for their share of an ERRA overcollection or PUBA/CAPBA balance they helped finance. This approach aligns with long-standing ratemaking principles, is simple to implement, and will produce a uniform approach for balancing account under collections across all utilities.

However, within D.20-12-038, the Commission applied the methodology inconsistently, and that short-coming should be repaired here. Over the Joint CCAs' objections, D.20-12-038 returned PG&E's PCIA Financing Subaccount (PFS) to bundled customers via the ERRA rather than the PABA.[49] As a result, some of the funds owed to currently bundled customers who depart PG&E service during the amortization period will never receive them. Because returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the PUBA,[50] the Joint CCAs argued it should have been paid back in the same manner prescribed by D.20-02-047 for an ERRA overcollection, *i.e.*, "reflected in the PCIA rate" to ensure any overcollection credit benefits "all customers who paid into the

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47 D.20-12-028 at OP 4 (ordering "a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of its Portfolio Allocation Balancing Account").

48 *See* CalCCA Opening Comments at 16-17 (describing how customer vintages are set with a mid-year cutoff, while PCIA and ERRA rates are (generally) set on a calendar year basis).

49 D.20-12-038 at 21-22.

50 A.20-07-002, Exh. JCCAs-1 at 41:11-13.

overcollection."[51] This approach would have comported with the approach already codified in SCE's PABA implementing advice letter, which returns the PUBA balance via the PABA, ensuring customers that are owed a refund would receive one.[52]

The PG&E decision did not, and could not, explain why those purported differences warrant such an inequitable outcome. The decision states only that "Southern California Edison structured its financing subaccount differently than PG&E, and therefore it is reasonable for PG&E to have a different approach to returning balances to bundled customers."[53] That is, the decision promoted PG&E's preferred accounting treatment over providing full refunds to ratepayers that paid into a balance they were owed. However, the Commission did state it "may consider structural changes to the [PFS] when we address PCIA framework issues in the appropriate proceeding."[54] The Commission should require such revisions now, and PFS charges and credits should be effectuated via PABA.

More broadly, recent decisions establishing three-year amortization periods for the PUBA balances for PG&E and SCE and the CAPBA for SDG&E did not address customer crediting for years other than 2021.[55] Thus, the crediting methodology adopted here also should be applied to the 2022 and 2023 portions of the three-year amortization period.

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[51] D.20-02-047 at 11.

[52] SCE AL 4084-E and SCE Preliminary Statement Section Q.3.b (stating "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA.").

[53] D.20-12-038 at 21-22.

[54] *Id*.

[55] D.20-12-028 at OP 4 and at 22 (SDG&E) ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); *id.* at 9 ("In this decision we do not rule on SDG&E's argument, made in its reply briefs, that the Commission should require departing customers leaving SDG&E in the middle of 2021 to forgo a refund, though we do approve a one-time transfer of the CAPBA overcollection due to

b. *Regardless of your response to the question above, please outline any process or tariff changes that would be required to implement this change.*

The IOUs' PABA preliminary statements should be modified as needed to reflect this approach consistently for all PABA and CAPBA/PUBA-related balancing accounts, including PG&E's PFS sub-account.

V. ERRA TRIGGER

The ALJ Ruling states:

> *The Joint IOUs recommended that the Commission adjust the ERRA trigger mechanisms to consider PABA balances, which may "cancel out" undercollections in ERRA and reduce the frequency of expedited ERRA trigger applications. CalCCA requested more details from the Joint IOUs in reply comments.*

a. *SCE and PG&E have already included PABA balances in their ERRA Preliminary Statements without Commission approval. Should the Commission sanction or penalize SCE and PG&E for acting without Commission approval?*

SCE and PG&E should not be sanctioned or penalized.

b. *Please comment on this proposal from an operational, legal and/or public policy perspective.*

As noted in the ALJ Ruling, CalCCA tentatively supported this proposal in its January reply comments, pending further details from the IOUs. For example, the Joint IOU proposal requires an ongoing calculation of bundled customers' share of the PABA balance which will be used as an offset to the ERRA in the calculation of the ERRA trigger. If the Joint IOU recommendation is adopted, each IOU should be required to include in its Monthly Reports the details supporting the PABA attribution to bundled customers and the determination of whether the combined ERRA and PABA balance reached or exceeded the ERRA trigger in that month.

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bundled customers into the 2020 vintage of PABA."); *see* D.20-12-035 at OP 6 (SCE); *see also* D.20-12-038 at 18, OP 1 (PG&E).

VI. CONCLUSION

CalCCA respectfully requests the Commission adopt its proposal to ensure consistent and transparent access to the data necessary to protect unbundled customers from rate shock, and to require consistent treatment of confidential data within the ERRA Forecast and Compliance proceedings. Further, CalCCA urges the Commission to adopt the other proposals discussed in the ALJ Ruling, commensurate with the recommended modifications herein.

Respectfully submitted,

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On behalf of
California Community Choice Association

October 1, 2021

ATTACHMENT A

Confidential Protocols for CCA Projects Slide

CONFIDENTIAL PROTOCOLS FOR CCA PROJECTS

- Our role as Reviewing Representative for California Community Choice Aggregators (CCAs) involved in Power Charge Indifference Adjustment (PCIA) matters require specific NDA conditions.
- Individuals directly involved in providing PCIA support are required to properly safeguard the confidential information and establish an ethics wall. Separation includes the following safeguards:
  - When reviewing or discussing any market sensitive data, the Reviewing Representative and those working with him/her shall employ all reasonable steps to ensure a physical separation from firm personnel who are not authorized Reviewing Representatives;
  - The Reviewing Representative shall be responsible for informing all firm personnel about the existence and terms of the Commission's confidentiality rules, and in particular the prohibition against sharing market sensitive information with Market Participants; and
  - The Reviewing Representative shall take all reasonable steps necessary to ensure that market sensitive information and files, including electronic files, are not accessible to firm personnel who are not authorized Reviewing Representatives.
- Confidential project files are stored in a restricted network location only accessible to those who signed the NDA (Dickman, Reger, Bernt, Johnson, Schuepbach, and Accardo).

Submit comment on Draft final proposal and draft tariff language

Initiative: Maximum import capability enhancements

1. Provide a summary of your organization's comments on the Maximum Import Capability (MIC) Enhancements draft final proposal:

The California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the Maximum Import Capability (MIC) Enhancements Revised Straw Proposal. CalCCA generally supports the California Independent System Operator (CAISO's) proposal, specifically the proposal to enhance transparency to facilitate trades more easily and increase the usage of available MIC.

2. Provide your organization's overall position on the draft final proposal: *

Choose:

- Support
- **Support with caveats – CalCCA supports the draft final proposal with caveats**
- Oppose
- Oppose with caveats
- No position

3. Provide your organization's comments on the improve transparency topic, as described in section 5.1:

CalCCA supports the CAISO's proposal to improve transparency. The CAISO proposes to make data publicly available through a web interface identifying the most up-to-date owners of MIC allocations at the branch group level including megawatt (MW) quantity, contact, and MWs available for trade and aggregate usage by branch group level after Resource Adequacy (RA) showings are submitted. Improvements to transparency will allow for load-serving entities (LSEs) to trade MIC more easily by identifying potential entities with MIC available to trade at different locations. This should result in increased MIC trades and usage. However, if improvements to transparency do not yield the expected improvements to MIC trading, CalCCA would support the CAISO undertaking an effort to investigate and understand barriers to MIC trading and full usage.

4. Provide your organization's comments on the Inclusion of contractual data from non-CPUC jurisdictional LSEs into the policy portfolio used for MIC expansion topic, as described in section 5.2:

CalCCA has no comments at this time.

5. Provide your organization's comments on the MIC Capability expansion requests topic, as described in section 5.3:

CalCCA supports allowing LSEs or other stakeholders with "legitimate reasons" to request an increase in MIC if deliverability is available.

6. Provide your organization's comments on the Step 13 – same day priority to existing RA contracts topic, as described in section 5.4:
CalCCA supports giving same-day priority in Step 13 to LSEs with existing RA contracts in proportion to the size of each requestor's RA contract.

7. Provide your organization's comments on the Tariff and Reliability Requirements BPM alignment of terms topic, as described in section 5.5:
CalCCA supports the CAISO clarifying its tariff and BPM language to be consistent with the current practices of 1) using two decimal places for MIC transfers, and 2) posting quarterly trading data publicly.

8. Provide your organization's comments on the other issues discussed in the proposal, as described in section 5.6:
CalCCA supports the CAISO's decision not to move forward with other issues discussed in previous iterations of the proposal including, developing an auction mechanism for allocating MIC, conducting deliverability studies after RA showings, releasing unused MIC, and changing the methodology for calculating MIC to include liquidity. The CAISO should move forward with the transparency, expansion, and Step 13 proposals and evaluate their effectiveness before considering additional changes to the MIC process. Improvements to transparency proposed in this initiative should result in more efficient trading and usage of MIC as discussed in 3 above.

If these changes do not yield the expected results, the CAISO should investigate existing barriers preventing MIC trading. DMM's comments indicate in August and September of 2019 and 2020, there were non-zero bi-lateral prices for MIC at certain branch groups on which there appeared to be unused MIC.[1] DMM correctly points out that these findings suggest there is room for improvement in the MIC process such that MIC on highly valued branch groups do not go unused. CalCCA previously expressed concern that MIC goes unused because parties have an incentive to hold onto MIC to use it for substitution to cover planned or forced outages of other RA resources. Clarifications from the CAISO indicate imports can only be substituted for forced outages on other imports. Comments from DMM state that external resources have not been used for substitution purposes for the last three years, suggesting LSEs appear not to regularly hold back MIC for substitution.[2] Accordingly, CAISO should investigate barriers preventing MIC trading if improvements to transparency do not yield the expected results.

9. Provide your organization's comments on the proposed initiative schedule and EIM Governing Body role, as described in section 6:
CalCCA reiterates its support for the EIM Governing Body Classification for this initiative.

10. Additional comments on the Maximum Import Capability Enhancements draft final proposal:
CalCCA has no comments at this time.

11. Provide a summary of your organization's comments on the Maximum Import Capability (MIC) Enhancements draft tariff language:

1 DMM Comments on Revised Straw Proposal at 2: https://stakeholdercenter.caiso.com/Common/DownloadFile/86140bdb-a417-4106-95cf-1012df2e5c03
2 *Id. at* 5.

CalCCA has no comments at this time.

12. Provide your organization’s comments on draft tariff language section 24.3.1 Inputs to the Unified Planning Assumptions and Study Plan:

CalCCA has no comments at this time.

13. Provide your organization’s comments on draft tariff language section 24.3.3 Stakeholder Input – Unified Planning Assumptions/Study Plan:

CalCCA has no comments at this time.

14. Provide your organization’s comments on draft tariff language section 24.3.5 Import Capability Expansion Requests:

CalCCA has no comments at this time.

15. Provide your organization’s comments on draft tariff language section 40.4.6.2.1 Available Import Capability Assignment Process:

CalCCA has no comments at this time.

16. Provide your organization’s comments on draft tariff language section 40.4.6.2.2.2 Reporting Process for Bilateral Import Capability Transfers:

CalCCA has no comments at this time.

17. Provide your organization’s comments on draft tariff language section 40.4.6.2.2.3 Other Import Capability Information Postings:

CalCCA has no comments at this time.

18. Additional comments on the Maximum Import Capability Enhancements draft tariff language:

CalCCA has no comments at this time.

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE CALIFORNIA ENERGY COMMISSION ON THE INFORMATIONAL WORKSHOP ON MIDTERM RELIABILITY MODELING
September 23, 2021

Docket Number 21-ESR-01
Energy System Reliability

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these comments to the California Energy Commission (Commission) in Docket 21-ESR-01 on the Midterm Reliability Analysis (MRA) presented at the *Informational Workshop On Midterm Reliability Modeling* (Workshop), held on Thursday, September 23, 2021.

II. COMMENTS

CalCCA applauds the extensive effort put forth by Commission staff to conduct this analysis. CalCCA has advocated for a loss of load expectation (LOLE) study within California Public Utilities Commission (CPUC) Integrated Resource Planning (IRP) proceeding to support the mid-term reliability procurement orders.[2] Additionally, CalCCA encouraged the CPUC to justify any procurement order requiring procurement of fossil fuel resources.[3] CalCCA is pleased

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Comments of the California Community Choice Association on the Proposed Decision and Alternate Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003, June 10, 2021 at 3-6.

[3] *Reply Comments of the California Community Choice Association on the Proposed Decision and Alternate Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003, June 15, 2021 at 3-4.

that the Commission is collaborating with the CPUC in conducting this analysis to determine the level of reliability achieved by current procurement orders, and to determine whether new gas capacity improves reliability compared to a portfolio of new preferred resources with equivalent Net Qualifying Capacity (NQC) values. This analysis is an important step in ensuring California's planning processes result in procurement that meets targeted levels of reliability. CalCCA urges the Commission and other agencies to continue to build off this effort such that long-term planning and procurement processes result in well-informed procurement orders and minimizes the need for future emergency procurement orders.

CalCCA is generally supportive of the analysis presented at the Workshop. The initial conclusions generated by the MRA, particularly the conclusion that a portfolio of preferred resources can provide equivalent system reliability to new gas resources,[4] are consistent with CCAs' commitment to renewable and preferred resources. For future modeling work by the Commission, CalCCA reiterates several of its recommendations made to the inputs of the study from its comments on the IPER Joint Agency Workshop of Summer 2021 Electric and Natural Gas Reliability.[5] These modifications would enhance the Commission's reliability modeling by assessing reliability under different resource availability assumptions reflecting recent trends.

First, the Commission should examine different sensitivity cases for Resource Adequacy (RA) imports, such as minimum, average, and maximum levels. Such sensitivities capture the uncertainty in the amount of imports that will be available to serve the California Independent System Operator (CAISO) balancing authority area load when needed. The Commission should

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4 *See Id.,* Presentation, Lead Commissioner Workshop; Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants (Aug. 20, 2021).

5 *California Community Choice Association Comments - On the IEPR Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability*, 21-IEPR-04, July 23, 2021.

focus primarily on conservative estimates of RA imports to understand the potential reliability impacts of resource retirements and tightening supply conditions throughout the west. Indeed, some of the data presented at the July 8, 2021, IEPR workshop indicates that the amount of imported RA made available to California has decreased over the last few years.[6] Thus, minimum historic RA imports may most reasonably reflect current trends and conservative expectations for future RA import availability.

Second, given the importance of hydro conditions on electric reliability, the Commission should evaluate different hydro availability sensitivity cases to inform reliability impacts of varying hydro conditions. The Commission could use publicly available data on hydro production it already compiles to do this analysis.[7] This summer's drought conditions highlight the importance of understanding how low hydro conditions impact reliability and should be considered should these conditions continue.[8] Table 1 below shows drought indices in the west, with darker colors indicating more severe droughts. Since 2021, the dark brown colors indicate that severe drought has increased, in both persistence and magnitude, beyond any level seen since 2000.[9]

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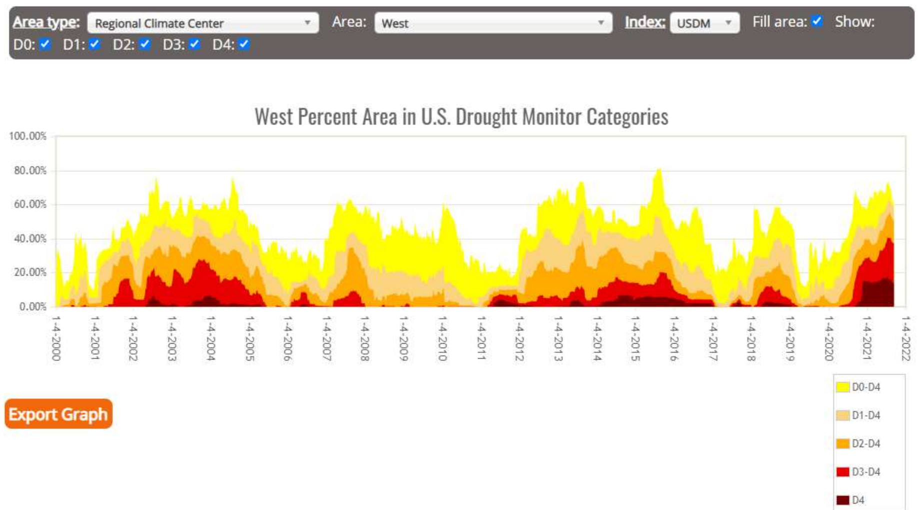
6 See Import Trends from the Grid Operator Perspective presentation, July 8, 2021: https://efiling.energy.ca.gov/getdocument.aspx?tn=238733.

7 Available at: https://ww2.energy.ca.gov/almanac/renewables_data/hydro/index_cms.php .

8 "Joint Statement from the CPUC President Marybel Batjer, CEC Chair David Hochschild, and California ISO CEO Elliot Mainzer on decision to procure additional energy resources for summer" cite drought conditions as contributing factor in the decision to procure additional capacity through the CAISO's Capacity Procurement Mechanism: http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-JointStatementandLetter.pdf.

9 U.S. Drought Monitor, Data, Time Series, https://droughtmonitor.unl.edu/CurrentMap.aspx . D0 is abnormally dry, D1 is a moderate drought, D2 is severe drought, D3 is extreme drought, and D4 is exceptional drought.

Table 1. U.S. Drought Monitor Data



Finally, when evaluating forced outages in future analyses, the Commission should consider the correlation of thermal derates of fossil gas resources and times of high heat. This consideration is critical in evaluating fossil gas resource availability.

III. CONCLUSION

CalCCA appreciates Commission staff's efforts in its Midterm Reliability Analysis and looks forward to further collaboration on future analyses.

Dated: October 4, 2021

(*Original signed by*)

Eric Little
Director of Regulatory Affairs
California Community Choice Association
(510) 906-0182 | eric@cal-cca.org

October 5, 2021

VIA ELECTRONIC MAIL

Mr. Eric Lee
Southern California Edison Company
P.O. Box 800
Rosemead, CA 91770
Eric.Lee@sce.com

Re: California Community Choice Association's Comments on Joint Utilities Proposed COVID Debt Relief Small Business Pilot in Compliance with Decision 21-06-036

Dear Mr. Lee:

Thank you for providing the opportunity to submit comments on the proposed COVID Debt Relief Small Business Pilot (Small Business Pilot) of Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric (SDG&E) (collectively, the Joint Utilities). The proposal for the Small Business Pilot, as set forth in the Draft Outline provided by the Joint Utilities (Draft Outline) and the Joint Utilities' presentation dated 9/28/21, is in response to the requirement in Decision (D.) 21-06-036 for the Joint Utilities to "work with interested stakeholders to propose a pilot with Small Business customers in disadvantaged communities."[1]

As proposed, the Small Business Pilot would allow the Joint Utilities to provide one-on-one energy management coaching to eligible small business customers on how to best reduce their existing bills, by utilizing IOUs' portfolio of rate options, bill management, load management, and energy savings programs. The Joint Utilities propose that third-party Community Based Organizations (CBOs) would be hired as "Energy Ambassadors" to conduct the pilot. However, during the 9/28/21 presentation, PG&E noted that it may choose to administer the pilot from "in-house," meaning it may not use Energy Ambassadors but instead may use PG&E employees to conduct the outreach.[2] Eligibility for the pilot includes small businesses in disadvantaged communities (DACs) with COVID-related arrearages, in specified cities and/or with a targeted percentage of specific customers (i.e., those with high arrears). Community Choice Aggregator (CCA) small business customers are eligible to participate in the pilot, although how a CCA customer can participate is unclear.

CalCCA provides the following comments on the Draft Outline and 9/28/21 presentation:

I. CCAs and CCA Programs Should Be Incorporated into the Small Business Pilot

The Small Business Pilot should include outreach regarding programs of both the Joint Utilities and CCAs that could have the impact of assisting small business customers to reduce their arrearages and promote sustained bill savings. While the Draft Outline states that "CCA small business customers

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[1] *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* D.21-06-036 (June 30, 2021) (Covid Debt Decision).

[2] PG&E also noted that it had not made a final decision on this issue.

are eligible to participate in the pilot," those CCA small business customers presumably would only receive counseling regarding IOU programs, and not CCA programs, despite all IOU and CCA customers paying for these programs through a Memorandum Account subject to Commission review.[3] Many CCAs have programs that can help small businesses achieve bill savings, load shifting, and energy savings. For example, Marin Clean Energy's (MCE's) commercial energy efficiency program provides commercial properties in MCE's service area with no-cost energy assessments and assistance to install money saving energy efficient equipment, as well as the "MCE Cares Credit" through March 31, 2022 providing a credit for certain small business customers. Clean Power Alliance provides a Peak Management Pricing Program to allow businesses to earn bill credits for powering down equipment during peak periods. Many more CCAs have similar programs.

CalCCA has concerns regarding the Small Business Pilot only providing counseling regarding utility programs, to the exclusion and detriment of CCA programs. CalCCA recommends inclusion of CCAs in the small business pilot similar to the Percentage of Income Payment Plan (PIPP) pilot currently being planned in the Disconnections proceeding, Rulemaking (R.) 18-07-005. If a certain number of small business customers are allowed in the small business pilot, a percentage share of those customers proportional to the customers of a CCA in that utilities' service territory could be CCA customers, similar to the PIPP pilot. The Energy Ambassadors could be trained in both IOU and CCA programs in that service territory, in order to benefit both bundled IOU customers, and unbundled CCA customers.

II. Pilot Eligibility Should Extend Beyond the CalEnviroScreen Definition of a DAC to Include Small Business Customers with the Highest Rates of Arrearages Over the Past 12 Months as Designated by IOUs and CCAs

The Joint Utilities proposed during the 9/28/21 presentation that DAC small business customers would be identified through the CalEnviroScreen tool of the California Office of Environmental Health Hazard Assessment. Given the widespread financial vulnerability of small businesses as a result of the Covid pandemic, CalCCA suggests that in addition to the CalEnviroScreen tool, the Joint Utilities could utilize eligibility characteristics similar to the PIPP eligibility for IOU and CCA customers. Specifically, CalCCA recommends that the Joint Utilities allow small business customers to be eligible for the small business pilot in zip codes (designated by both IOUs and CCAs) with the highest rates of small business customer arrearages during the past 12 months.

III. The Joint Utilities Should Provide Estimated Size and Cost Information to Stakeholders Regarding the Small Business Pilot

The Draft Outline proposes that "the Commission authorize the budgets proposed in the [Advice Letter] and the IOUs recover the costs through a new two-way balancing account."[4] The Covid Decision allows the IOUs to track costs of required programs in the existing COVID-19 Pandemic Protection Memorandum Accounts, which will be subject to Commission review.[5] However, the Draft Outline does

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3 Covid Debt Decision, Ordering ¶7, at 51 (allowing IOUs to recover costs through the COVID-19 Pandemic Protection Memorandum Accounts, which will be subject to Commission review applicable to such memorandum accounts).

4 Draft Outline at 7.

5 Covid Debt Decision, Ordering ¶7, at 51.

not provide estimated costs, the potential scope, and the number of potential customers in the Small Business Pilot. If CCAs are able to participate, it is also unclear as to how costs will be recovered. As CCA customers generally will, along with IOU customers, presumably be responsible to pay for the Small Business pilot program (either through the Public Purpose Programs Charge or other customer charge), the estimated costs are an important component of the CCAs' evaluation of this program, and therefore should be furnished to stakeholders.

IV. Pilot Outreach Should Only Be Conducted by Third Party Energy Ambassadors with Equal Knowledge of IOU and CCA Programs Benefitting Small Business Customers

During the 9/28/21 presentation, PG&E raised the possibility of conducting the Small Business pilot "in-house," and not using CBOs or third-party Energy Ambassadors to provide the counseling under the pilot. CalCCA has concerns with CCA customers receiving counseling regarding IOU or CCA programs from an IOU employee.[6] In addition, if CCAs are able to participate in the Small Business Pilot, a third-party Energy Ambassador would be best equipped to fairly communicate programs of both IOUs and CCAs. In fact, joint marketing of IOU and CCA programs benefitting small business customers through a single point of contact with a third-party Energy Ambassador would be the most convenient and effective way to reach and assist small business customers in need. Under all circumstances, therefore, a third-party Energy Ambassador would be the best option.

CalCCA thanks the Joint Utilities for their consideration of these comments on the proposed Small Business Pilot.

Respectfully,

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Evelyn Kahl

Evelyn Kahl

General Counsel and Director of Policy

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6 In fact, such communications between an IOU employee and a CCA customer could raise issues under the Code of Conduct governing the treatment of CCAs by IOUs. *See Decision Adopting a Code of Conduct and Enforcement Mechanisms Related to Utility Interactions with Community Choice Aggregators, Pursuant to Senate Bill 790,* D.12-12-036 (Dec. 28, 2012).

CALCCA
ADVANCING LOCAL ENERGY CHOICE

October 5, 2021

VIA ELECTRONIC MAIL

Mr. Edward Randolph
Deputy Executive Director for Energy and Climate Policy
California Public Utilities Commission Energy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: California Community Choice Association's Protest of Pacific Gas and Electric Company's Tier 1 Advice Letter 6323-E, *Procurement for Summers 2022 and 2023 Under Decision 21-02-028 and Decision 21-03-056*

Dear Mr. Randolph:

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of Pacific Gas and Electric Company's (PG&E) Advice Letter 6323-E (Advice Letter). PG&E submitted the Advice Letter on September 15, 2021, seeking approval of an amendment to extend an existing agreement set to expire on April 30, 2022, by 18 months and to enable the provision of additional energy and capacity through summers 2022 and 2023.

PROTEST

CalCCA does not object to the Commission authorizing an extension of the existing agreement by 18 months. However, the Commission should not authorize the requested cost allocation mechanism (CAM) cost recovery for 2023 through this advice letter process. The year 2023 extends beyond the duration of procurement authorized in Decision (D.) 21-03-056. While D.21-03-056 allowed for procurement of contracts with durations that would extend beyond 2022, the 17.5 percent target would not extend beyond 2022.[3] Therefore, clarification is needed around how costs should be allocated for contracts executed to meet D.21-03-056 that extend

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

2 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, March 25, 2021 (D.21-03-056).

beyond 2022. The Commission must consider the methodology for cost allocation holistically within Rulemaking (R.) 20-11-003, rather than through an advice letter.

1. CALCCA Does Not Object To PG&E's Request For Contract Extension

PG&E seeks approval to extend an existing agreement with Tesoro Refining & Marketing Company LLC for its Martinez Cogeneration facility to make the resource available for both summer 2022 and summer 2023. This modification would extend the agreement by 18 months, from its current end date of April 30, 2022 to October 31, 2023.[4] CalCCA does not object to PG&E's request to extend the contract by 18 months to ensure the resource is available through summer 2022, consistent with the procurement authorized under D.21-03-056.

2. The Methodology for Allocating the Costs of Contracts With Duration Beyond 2022 Should be Considered Holistically in R.20-11-003, Rather Than Through an Advice Letter

Within D.21-03-056, the Commission adopted a Planning Reserve Margin (PRM) of 17.5 percent applicable to the three investor-owned utilities (IOUs) that were to procure on behalf of all customers. In doing so, the Commission determined that for 2021 and 2022, the IOUs should allocate the costs associated with those contracts through CAM but since only the IOUs would have a 17.5 percent PRM for Resource Adequacy (RA), the RA attributes of the contracts would remain with the IOUs. D.21-03-056 allowed for procurement of contracts with durations that would extend beyond 2022 while the 17.5 percent target would not extend beyond 2022.

PG&E's Advice Letter requests CAM cost recovery for the contract extension through and including October 31, 2023.[5] However, there is significant clarity needed regarding what should happen to the costs and benefits of resources procured in response to D.21-03-056 beginning in 2023 should any of those contracts continue beyond 2022. In R.20-11-003, CalCCA submitted reply testimony[6] and an opening brief[7] requesting the Commission clarify the modified CAM treatment for procurement mandated in D.21-03-056 so that the costs and benefits are fairly allocated and cost shifts do not occur.

These significant outstanding questions extend beyond the single contract extension requested by PG&E. Therefore, the Commission should not approve CAM cost recovery for the contract extension requested by PG&E in the Advice Letter. Instead, the Commission should

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4 PG&E Advice Letter at 3-4.

5 PG&E Advice Letter at 4.

6 *Reply Testimony of Marie Y. Fontenot on Behalf of California Community Choice Association*, Sept. 10, 2021 at 7-8: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/reply-testimony/calcca-reply-testimony.pdf.

7 *California Community Choice Association Opening Brief*, Sept. 20, 2021 at 12-13: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M407/K951/407951034.PDF

holistically examine how costs and benefits should be allocated for contracts extending beyond the timeline of D.21-03-056 within R.20-11-003.

CONCLUSION

CalCCA thanks the Energy Division for its review of this protest and asks that the Commission approve the PG&E contract extension, and that the cost allocation of this extension and other contracts extending beyond 2022 be evaluated wholistically in R.20-11-003.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

Evelyn Kahl

General Counsel and Director of Policy

cc via email:
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Service Lists: R.20-11-003, R.19-11-009, and R.20-05-003

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

Order Instituting Rulemaking To Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AND ALTERNATE PROPOSED DECISION CLARIFYING AND IMPROVING CONFIDENTIALITY RULES FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

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On behalf of California Community Choice Association

October 6, 2021

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- Reject the APD as the six-month confidentiality protection for contract pricing beginning from the date of contract execution or approval fails to adequately protect market-sensitive information and disadvantages CCAs as compared to IOUs; and

- Modify Ordering Paragraph 3 of the PD/APD to clarify that a contract amendment does not reduce the otherwise applicable confidentiality window for contract price information.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking To Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AND ALTERNATE PROPOSED DECISION CLARIFYING AND IMPROVING CONFIDENTIALITY RULES FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

The California Community Choice Association (CalCCA)[1] respectfully submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, on Administrative Law Judges Manisha Lakhanpal and Carolyn Sisto's proposed *Decision Clarifying and Improving Confidentiality Rules for the Renewables Portfolio Standard Program* (PD), issued on September 16, 2021, and Commissioner Clifford Rechtschaffen's alternate proposed *Decision Clarifying and Improving Confidentiality Rules for the Renewables Portfolio Standard Program* (APD), issued on September 16, 2021.

I. INTRODUCTION AND SUMMARY

As local governmental agencies, California's community choice aggregators (CCAs) are committed to operating in an open and transparent manner, and ensuring that the public has

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

reasonable access to data on the procurement of renewable energy by California's load serving entities (LSEs). As set forth below, CalCCA supports the PD as it would both expand the types of renewables portfolio standard (RPS) procurement information that the public has access to as well as shorten the current timeframes for confidential treatment of RPS procurement information. The PD achieves these goals while also sufficiently protecting market-sensitive information and not disadvantaging any one class of market participant over another. The APD, however, should be rejected as its proposed six-month confidentiality protection for contract pricing fails to adequately protect market sensitive information, and disadvantages CCAs as compared to investor-owned utilities (IOUs) given that the effect of the proposal is that IOUs would get a longer period of confidentiality protection than CCAs. Additionally, CalCCA identifies one recommended clarification to the PD and APD regarding the confidentiality treatment associated with contract amendments.

CalCCA therefore provides the following recommendations:

- Adopt the PD as it ensures expanded public access to RPS procurement information while sufficiently protecting market-sensitive information and not disadvantaging any one market participant over another;
- Reject the APD as the six-month confidentiality protection for contract pricing beginning from the date of contract execution or approval fails to adequately protect market-sensitive information and disadvantages CCAs as compared to IOUs; and
- Modify Ordering Paragraph (O¶) 3 of the PD/APD to clarify that a contract amendment does not reduce the otherwise applicable confidentiality window for contract price information.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION

The PD should be adopted, as it appropriately balances the substantial public interest in RPS program information with the need to protect market-sensitive RPS procurement data to allow all classes of market participants to conduct their procurements competitively and fairly.

The expansion of the types of RPS procurement information that the public will be able to access, as well as the shortening of the current timeframes for confidential treatment of RPS procurement information, are appropriate given evolving market conditions, including the shortened timeframe for renewable projects to come online. CalCCA supports the PD's: (1) approach to assessing the confidentiality protections for RPS procurement data; (2) reduction of the window of confidentiality for RPS compliance forecast data and RPS net short positions from three years to two years; and (3) proposal to make a contract price publicly disclosable the sooner of 30 days after commercial online date (COD) or three years after contract approval or execution. Accordingly, CalCCA requests that the Commission adopt the PD.

A. CalCCA Supports the PD's Approach to Assessing the Appropriate Confidentiality Protections for Renewable Procurement Data

CalCCA agrees with the PD's approach to analyzing the extent of confidentiality protection that should be provided to each type of RPS information. Specifically, CalCCA agrees that the Commission should "start with presumptions that information should be publicly disclosed, Decision (D.) 06-06-066 intended to grant greater access to the RPS data, and that any party seeking confidentiality bears a strong burden of proof."[2] The PD recognizes that in performing this analysis there is value in ensuring that the public has adequate access to information on renewable procurement by LSEs and on the status of individual LSEs in meeting the RPS program requirements.

B. The Commission Should Adopt the PD's Reduction of the Window of Confidentiality for RPS Compliance Forecast Data and RPS Net Short Positions from Three Years to Two Years

CalCCA supports the PD's reduction of the confidentiality period for energy and capacity forecast data and RPS net short positions from three years into the future down to two years into

[2] PD at 20.

the future. The PD rightly concludes that D.06-06-066's primary justification for providing three years of protection to forecast capacity and energy data was that three years was the typical amount of time that it takes a project to come online after contract execution.[3]

In its reply comments on the *Assigned Commissioner's Ruling Requesting Comments on Staff Proposal to Clarify and Improve Confidentiality Rules for the Renewables Portfolio Standard Program*, issued on February 27, 2020 (ALJ Ruling), CalCCA urged the Commission to reevaluate this determination based on the data that the Commission has access to regarding the average time from contract execution to the COD.[4] The PD provides a thorough and detailed analysis on this issue, finding that this time period has fallen significantly since 2006, and thus the key assumption on which this confidentiality rule was based has changed. CalCCA agrees that, in light of these changed facts, the Commission is justified in reducing the confidentiality window for this forecast data.

C. The Commission Should Adopt the PD's Proposal to Make Contract Price Publicly Disclosable the Sooner of 30 Days after COD or Three Years after Contract Approval or Execution

As CalCCA stated in opening comments on the ALJ Ruling, one year of confidentiality protection for contract price data would largely prevent other bidders from gaining access to this sensitive pricing information during ongoing negotiations that resulted from the same solicitation.[5] Based on factual support, the PD finds that there is a need for this protection,

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[3] PD at 31-32.

[4] *California Community Choice Association Reply Comments on Assigned Commissioner's Ruling Requesting Comments on Staff Proposal to Clarify and Improve Confidentiality Rules for the Renewables Portfolio Standard Program* (April 17, 2020), Rulemaking (R.) 18-07-003 at 7.

[5] *California Community Choice Association Comments on Assigned Commissioner's Ruling Requesting Comments on Staff Proposal to Clarify and Improve Confidentiality Rules for the Renewables Portfolio Standard Program* (May 30, 2020) (CalCCA Comments on ALJ Ruling), R.18-07-003, at 4. CalCCA stated:

noting that "making RPS prices public 30 days after the commercial operation date . . . will avoid market manipulations and protect ratepayers from higher costs."[6] More specifically, the PD finds that a window of confidentiality protection that is at least one year in duration from contract execution is "*long enough to let all contract negotiations close*, guarantees a period when bid prices remain confidential from contemporaneous bids, adds certainty to the market, and is non-discriminatory."[7] CalCCA concurs that there is strong factual support for the PD's conclusion.

While there is a potential difference in the timing for releasing this information for IOU contracts as compared to CCA and Electric Service Provider (ESP) contracts, this difference is minor because most projects come online within three years of contract execution. For the large majority of contracts with new facilities, the window of confidentiality protection for contract pricing information will be the same for IOUs, CCAs, and ESPs. Therefore, CCAs are not uniquely disadvantaged as compared to IOUs.

As a result of the above, CalCCA recommends that the Commission adopt the PD.

> [A]n LSE may issue a solicitation for renewable procurement where multiple bids may be accepted and where the solicitation remains open for a period of time longer than six months. If an LSE entered into contract negotiations with two separate counterparties that both responded to a single solicitation and the pricing information from one of those contracts was made public while that LSE was still in negotiations with the other counterparty, then that LSE would be at a significant contracting disadvantage. The counterparty would not only know the LSE's needs based on the solicitation, but would also know the price that the LSE had agreed to in response to that solicitation. Such disclosure has the potential to increase the contract price that the parties would ultimately agree to for that remaining contract or otherwise affect non-price terms and conditions that are indirectly reflected in the price. This scenario is particularly likely to occur for those LSEs that will be engaged in significant renewable procurement over the coming years. Extending the timeframe for making pricing information publicly-available from six months to one year after contract execution would reduce this risk because in most cases the solicitation would have closed and/or contract negotiations would have concluded.

Id.

6 PD at 42.

7 PD at 42-43 (emphasis added).

III. THE COMMISSION SHOULD REJECT THE APD

The Commission should reject the APD as it errs in providing only six months of confidentiality protection for contract pricing from the date of either contract execution or contract approval, as applicable. As demonstrated in the record, this proposed timeline does not provide adequate protection to keep market-sensitive information from being disclosed during ongoing negotiations, which could result in harm to end-use electricity customers. Moreover, the structure of this proposal would significantly disadvantage CCAs as compared to IOUs. The Commission should therefore reject the APD, and instead adopt the PD's contract pricing confidentiality proposals which are not subject to the APD's infirmities.[8]

A. The APD Provides an Inadequate Justification for a Six-Month Window of Confidentiality Protection for Contract Price Information

The APD's primary justification for adopting a six-month window of confidentiality protection for contract pricing information is that: (a) there has been a sharp reduction in renewable contract prices from 2006 to 2019; (b) there was a significant increase in the number of bids and bidders between the IOUs' 2006 solicitations and 2011 solicitations; and (c) there is a large number of renewable projects currently in the California Independent System Operator's (CAISO's) queue. However, these facts do not support the APD's determination, and further, do not outweigh the clearly established fact that disclosing very recent contract price information would materially disadvantage an LSE, in particular a CCA, during ongoing negotiations.

The sharp increase in renewable projects and decrease in contract prices has not simply occurred naturally in the marketplace. Instead, the various procurement mandates on the LSEs have sharply increased the demand for renewable procurement. This demand has been driven not

8 CalCCA notes that there are other differences between the PD and the APD; CalCCA takes no position on these other differences at this time.

only by the RPS procurement mandate in Senate Bill 100 of 60 percent renewables by 2030 but also by the need to comply with the cap-and-trade program, as well as meet locally adopted renewable targets and greenhouse gas reduction goals. Further, the contract price reductions are significantly influenced by the reduction in the cost of photovoltaic modules and wind turbines along with other cost reductions in installation and labor, which are associated with a maturing industry. This cost reduction is not solely or primarily the result of market pressure. Simply stated, the APD's six-month window of confidentiality protection is not supported by facts showing that supply exceeds demand to such a degree that pricing information has little value.

Further, the fact that there are a large number of bidders market-wide may not be relevant to an LSE that is seeking renewable procurement with specific characteristics, such as the size, location, technology type, and deliverability characteristics. An LSE may still only have a small number of bidders that qualify for a specific solicitation, so the fact that there are a large number of bidders market-wide is irrelevant to a determination of whether contract price information would negatively disadvantage that LSE in its negotiations. For CCAs in particular, this is likely to be more common because of the procurement policies adopted by their local governing boards that may restrict permissible location and technology types.

Finally, while the APD notes that the average RPS contract price reached a historic low of $28/MWh in 2019, the 2021 Padilla Report shows that RPS contract prices increased to $35/MWh in 2020. This included an increase in the average contract price for wind and solar projects. Given increases in demand to meet compliance requirements and local policies, it is unclear that prices will continue the same historic downward trend.

B. The APD Makes an Incorrect Conclusion Regarding the Value of Recent Contract Price Data During Ongoing Negotiations

The APD concludes that a six-month delay in disclosing contract price information would prevent any potential negative impacts on ongoing solicitations because: (a) the bid deadline would have passed by the time a pending contract is approved or executed; (b) bid information would be substantially out of date due to the time that generally elapses between the submittal of bids and contract execution; and (c) the information would not result in higher bids in a pending solicitation due to the "overriding impact of competition from a larger number of bidders seeking contracts."

This analysis incorrectly focuses on the impact of bid information and the potential for new bids to be submitted that would be informed by this prior bid information. As CalCCA described in its comments on the ALJ Ruling, the primary risk associated with releasing contract price information six months after contract execution is not that it would influence new bids, but instead that it could affect ongoing negotiations from the same solicitation. Even in the later stages of negotiations there are a wide variety of reasons why the contract price or other key commercial terms may need to be re-negotiated. This could include: (a) an unanticipated change to the guaranteed COD due to permitting, interconnection, or land-acquisition delays; (b) a change in the size of the project due to availability of parts or issues with a site; or (c) new obligations on the seller or modifications to the project due to changes in Commission procurement requirements, particularly for projects co-located with storage projects. In such circumstances, the seller would be materially advantaged by having access to a fully executed contract from the same solicitation with the same LSE. The likely result is that the seller will negotiate a more favorable price or other commercial terms, passing those costs on to customers.

Similarly, the time that has elapsed since the submittal of the bid is irrelevant to the concerns raised above regarding the impacts to ongoing negotiations. The key concern is not that the seller would learn of another bid price, but that the seller would have access to a fully executed contract from the same solicitation with the same LSE that includes price and all other key commercial terms. The amount of time that has elapsed since the bid was submitted is irrelevant to this issue.

Finally, the APD's conclusion that overriding competition would eliminate the value of this pricing information is not supported by facts and incorrect. As described above, the fact that there are a large number of potential projects market-wide does not mean that LSE demand for these projects is not also commensurately high. Further, in the scenario where an LSE must renegotiate key commercial terms late in the process, it would not be a simple matter for an LSE to simply walk away from the project and return to the market and issue a new solicitation. Beyond the cost impacts, the LSE may need that specific project (with the associated COD) to meet compliance deadlines. Additionally, there may only be a limited number of projects that meet the specific procurement needs of the LSE, including the CCA's locally adopted policies. Further, for many CCAs, a solicitation is unlikely to result in so many bids that the CCA's recent contract price information would provide no value to a seller.

Therefore, the APD's conclusion that six months of confidentiality protection is adequate to prevent the release of market sensitive information and protect end-use electricity customers is unsupported and incorrect.

C. The APD's Proposal Regarding the Time Period for Disclosing Contract Price Data Should Be Rejected as it Provides Substantially Greater Protection to IOU Contract Price Data Than CCA Contract Price Data

The APD is structured such that contract price data would be disclosable six months after contract execution for contracts that do not require Commission approval and six months after the date of approval for those contracts that do require Commission approval. While the Commission lacks the authority to approve CCA and ESP contracts, a significant percentage of IOU contracts require some level of Commission approval. This creates a structure where for the major IOU RPS contracts, the confidentiality window will be substantially longer than for similar contracts executed by CCAs and ESPs.

Based on a review of Commission resolutions approving IOU RPS contracts, it appears that a typical time period between IOU contract execution and Commission approval ranges from three to six months with some contracts being approved as late as twelve months after contract execution. This means that IOUs would regularly receive a 50 to 100 percent greater time period of confidentiality protection than a CCA. Crucially, this additional time would often provide the IOU with at least one year between contract execution and the public disclosure of contract price data. This is the amount of time that would be necessary for CCA's to protect ongoing negotiations from the influence of this pricing data. Therefore, one year of protection would regularly be provided to IOUs, while being denied to CCAs. Because of this difference, the APD's proposal would uniquely disadvantage CCAs and should be rejected.

The APD asserts that this is only a minor difference in timing and is justified by D.06-06-066. Specifically, the APD cites to pages 54-55 of D.06-06-066 and Conclusions of Law 15 and 23 to support this proposal. Nothing in the text of these citations justifies providing IOUs with a 50 to 100 percent greater time period of protection for contract price data. Instead, these citations merely note that there may be differences between the confidentiality protections provided to different classes of entities, and that customer harm associated with the release of data can differ depending on factors such as the size of the entity and the entity's market position. The APD provides no justification for this discrepancy in the treatment between different classes of entity, and accordingly this difference cannot be legally sustained.

As a result of the above, CalCCA recommends that the Commission reject the APD.

IV. CLARIFICATION TO PD AND APD

A. The Commission Should Clarify the Impacts of an Amendment as Set Forth in Both the PD and APD

Both the PD and APD include the same language regarding the confidentiality protection for contract amendments, specifically that "if a contract is amended, this shall not modify the confidentiality requirements that apply to prior versions of the agreement . . ."

CalCCA generally agrees with this characterization, and clearly an LSE should not be able to avoid making contract data public by simply executing new amendments to the contract. However, the associated ordering paragraph can be read to have an unintended impact. As currently drafted, O¶ 3 of the PD and APD appears to require that the terms of an amendment be made public 30 days after execution regardless of whether the original contract is still within the confidentiality window. For example, an LSE could amend a contract six months after contract execution and still be well before the PD's proposed protection window of 30 days after COD or three years from the contract execution or approval date. Read literally, O¶ 3 would require public disclosure of the amendment, which may include key commercial terms, even though the underlying contract is still afforded confidentiality.

O¶ 3 of both the PD and APD should be clarified to state that the terms of an amendment are publicly disclosable the later of 30 days after the date of the contract amendment execution or the date on which the underlying contract becomes publicly disclosable.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these opening comments on the PD and the APD.

Respectfully submitted,

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APPENDIX A

CALCCA's Proposed Changes to Findings of Fact, Conclusions of Law and Ordering Paragraphs of the Proposed Decision and Alternate Proposed Decision

CHANGES TO FINDINGS OF FACT

None

CHANGES TO CONCLUSIONS OF LAW

None

CHANGES TO PD/APD ORDERING PARAGRAPHS

- PD/APD Ordering Paragraph 3. Retail Sellers amending a Renewables Procurement Standard procurement contract shall not modify the confidentiality requirements that apply to prior versions of the agreement, including the time frame for public information. After an amendment, the terms of the contract amendment are public the later of (i) 30 days after the new contract execution date, or (ii) the date on which the original contract becomes publicly disclosable.

10/20/21 and 11/03/21 RA Track 3B.2 Workshops
Resource Counting Questions

In order to assess the various proposals to implement a slice of day approach, CalCCA and IEPA have developed the following questions that presenters should address within their proposal/presentation. Not all questions may be applicable to a specific presentation, but these questions can serve as a starting point for evaluating options.

<u>Resource counting and slice definition</u>

1. Resource capability for resources like wind, solar, and hydro can vary considerably at different times of day and from the beginning to end of a season. How does the proposal account for this?

2. How often will slices be re-defined? Will resource counting updates follow the same timeline? How granular will the calculations be (i.e., different exceedances for each slice)?

3. How would a resource count if slice duration does not align with resource duration? For example, a four-hour minimum duration requirement and four-hour slices align. If the slices are shorter or longer than four-hours, how is the resource counted?

4. If a net load approach is used, how will wind and solar resource contributions be deducted from an LSE's gross load? Will this be top down based on LSEs getting a share of aggregate wind/solar profiles or bottoms up based on an LSE's specific resources under contract? Who will review and validate the contributions under each approach?

5. How will LSEs get credit for the slices procured through the local purchases made by the CPE? How would CPE crediting to LSEs work under a net load approach when the CPE is procuring RA from wind or solar?

6. Will each resource be assigned an NQC for each slice?

<u>Energy Sufficiency</u>

1. How does the proposal ensure energy sufficiency in all hours (beyond the peak or net-peak hour of a slice)?

2. How does the proposal address use-limited resources that have limitations (i.e., daily, monthly, annual use limits) that impact the energy they can provide?

3. How does the proposal treat storage, including:

    a. How does the proposal account for the need to charge storage?

    b. Can storage resources count in consecutive buckets given the need to recharge after they have been dispatched?

c. How will the charging hours account for battery inefficiency?

d. How does the proposal apply to storage with different durations (i.e., 4-hour storage and storage with longer durations)?

Transactability

1. Are slices (or slice obligations) bundled or can a resource sell to multiple LSEs for different slices?

2. If unbundled, how would RA showings be validated to account for resources selling the same capacity to different LSEs in different slices?

3. If bundled, how does the proposal prevent over-procurement where individual LSEs are long for certain slices because they cannot closely tailor their portfolios' generation profiles to their loads and are unable to sell the excess capacity other LSEs?

4. If SCE's hourly approach were adopted, would LSEs be able to sell hourly blocks of RA in hours in which they are long to other LSEs?

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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 (Filed June 29, 2017)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON DATA-RELATED PCIA ISSUES

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On behalf of
California Community Choice Association

October 8, 2021

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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 (Filed June 29, 2017)

REPLY COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON DATA-RELATED PCIA ISSUES

Pursuant to Administrative Law Judge (ALJ) Wang's September 17, 2021 e-mail ruling (ALJ Ruling), the California Community Choice Association[1] (CalCCA) hereby submits these reply comments on data-related Power Charge Indifference Adjustment (PCIA) issues.

The Direct Access Customer Coalition (DACC) and Alliance for Retail Energy Markets (AReM)'s Opening Comments recognize the urgent need for reform to increase transparency and access to data related to the balancing accounts that underlie PCIA rates. "[I]f a balance is increasing or decreasing from month to month, it can be important to understand why so as to better estimate what the end of the year balance of the [Energy Resource Recovery Account (ERRA)] and [Portfolio Allocation Balancing Account (PABA)] would be as such balances will be directly collected from the CCA customers."[2] The investor-owned utilities' (IOUs') bundled

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] R.17-06-026, *Response of AReM/DACC to the September 17, 2021 Email Ruling of ALJ Stephanie Wang*, at 2 (Oct. 1, 2021) (DACC/AReM Response).

customers enjoy the protections such data provide, and unbundled customers should have the same.

CalCCA's detailed Opening Comments already address most of the arguments Southern California Edison Company (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas and Electric Company (PG&E) (collectively, "Joint IOUs") raise in opposition to the transparency necessary to protect unbundled customers. Those Opening Comments demonstrate how the Portfolio Allocation Balancing Account (PABA) balances are volatile, comprise a large part of the PCIA revenue requirement and are based extensively on actual IOU cost and revenue data that is *solely* in the IOUs' possession.[3] The Opening Comments show how the data at the heart of CalCCA's proposal[4] underlie those PABA balances and are necessary for the community choice aggregators (CCAs) and their customers to understand fundamental market dynamics in order to plan for large swings in the PCIA to which unbundled customers are currently exposed.[5] As such:

- Providing the data related to the balancing accounts that underlie PCIA rates is in the public interest, despite IOU contentions' otherwise;[6]

- The Joint IOUs counter-proposal to provide *less* data will only make matters worse and should be rejected;[7] and

3 R.17-06-026, *Opening Comments of the California Community Choice Association on Data-Related PCIA Issues*, at 19 (Oct. 1, 2021) (CalCCA Opening Comments).
4 R.17-06-026, *California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, at 22 (Jan. 22, 2021).
5 CalCCA Opening Comments at 10-19.
6 R.17-06-026, *Joint Response of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) to Administrative Law Judge's Ruling Requesting Comments on ERRA-Related PCIA Issues*, at 6-7 (Oct. 1, 2021) (Joint IOUs Response).
7 *Id.* at 4-5.

- The data are clearly needed for CCA planning, and neither the public monthly reports nor the PCIA Energy Resource Recovery Account (ERRA) Forecast proceeding provide the year-round data needed.[8]

The CalCCA Proposal will result in CCA representatives receiving the *same* data they already receive under the *same* framework in which they already receive it.[9] The IOUs' arguments that the CalCCA proposal creates some kind of grave danger akin to the 2000-2002 Energy Crisis are vastly overstated and incorrect.[10]

The Non-Disclosure Agreement (NDA) CalCCA contemplates is just as restrictive as the model NDA, with the only difference being the use of a one-year, renewable term rather than a specific docket. Nothing in California Public Utilities Commission (Commission) precedent or statute prevents the Commission from recognizing the need for, and then creating, a non-docket specific NDA.[11] After all, Decision (D.) 11-070-028 created a *model* NDA, not an NDA to be applied in all circumstances. Statute, D.06-06-066, and D.11-07-028 do not bind the Commission to its existing NDA with no flexibility to address changing circumstances.[12] These Reply Comments do not rehash these three issues since they have already been addressed in CalCCA's Opening Comments.

Instead, these Reply Comments demonstrate:

- There is no incremental burden to the IOUs in aligning the data requirements established within the ERRA Forecast Proceedings (Question 1);

- A five-day turn-around is appropriate for what are essentially workpapers (Question 1);

8 *Id.* at 6-7, 9, 12-13, 14-15.
9 CalCCA Opening Comments at 10-19.
10 Joint IOUs Response at 9.
11 CalCCA Opening Comments at 15-19.
12 Joint IOUs Response at 12-13.

- Under CalCCA's proposal, no confidential data will ever be provided to CCA decision-makers (Question 2);

- PCIA modeling results would be $/kWh figures, akin to those provided in the IOUs' own ERRA applications, and would not reveal the price an LSE is willing to pay for energy or capacity (Question 2);

- Some, but not all, of the IOUs' suggestions for additional NDA safeguards appear reasonable (Question 2);

- The IOUs' shortcoming on labeling data as confidential is the systematic misapplication of D.06-06-066—the inconsistency between utilities is evidence of that misapplication (Question 3);

- DACC/AReM's request for a modified NDA should be explored (Question 3);

- The IOUs proposal to create a default approach to returning year-end balances, with exceptions proposed in ERRA proceedings, should be adopted (Question 4); and

- The IOUs should detail how they derive bundled customers' share of the PABA balance when combining it with the ERRA balance to avoid unnecessary ERRA triggers (Question 5).

CalCCA addresses each of these issues in response to each question raised in the ALJ Ruling, in turn, below.

I. THE IOUS PROTEST BURDENS THEY ALREADY MEET (QUESTION 1)

In three decisions resolving the three IOUs' 2021 ERRA Forecast applications, the Commission ordered each IOU to provide similar data in future proceedings;[13] obligations with which the IOUs' Opening Comments state they already comply. [14] Nonetheless, citing unspecified complications resulting from "unique operational systems and processes," PG&E states it cannot make the "operational changes to fully align the information and data produced

13 D.20-12-035 at Ordering Paragraph (OP) 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.

14 Joint IOUs Response at 2-3.

within SCE's reports." [15] Because the IOUs do not identify those changes, it is unclear what changes PG&E would be required to make in order to comply with the Commission's directive. Its ordering paragraph differs from SCE's ordering paragraph by only *one or two words*.[16]

While SDG&E's reporting largely aligns with SCE's reports despite the difference in language between the two orders,[17] the utility suggests it may be overwhelmed by an obligation it already meets. SDG&E states the data they already provide is more than what is provided to the Commission, is beyond what the utility uses in its ERRA Forecast case, and may change in the November Update.[18] None of these arguments should persuade the Commission.

First, SDG&E should be required to submit the same data as part of its monthly reports to the Commission that it submits to the CCAs within the forecast proceeding. Such data have assisted the CCAs to date and likely would help the Commission better understand the forces driving those balancing account balances to the benefit of all ratepayers and other stakeholders. Second, SDG&E fails to establish there is an incremental burden from its existing obligations under D.21-01-017. Based on its productions to date, SDG&E would not need to change its existing reporting in order to meet the standard set forth in SCE's D.20-12-035, and its success in meeting those obligations undermines its suggestion it cannot do so going forward.

The Joint IOUs also take issue with extending the five business-day time period for the provision of workpapers that exists for PG&E to all three IOUs, suggesting the existing ten business day timeline for discovery would be more appropriate. [19] The Commission should not adopt this change. The ten-day timeline applies to all types of discovery that may be served in a

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15 *Id.* at 4.
16 *Compare* D.20-12-038 at 31-32 and OP 4 to D.20-12-035 at OP 8.
17 *Compare* D.21-01-017 at OP 6 *to* D.20-12-035 at OP 8.
18 Joint IOUs Response at 4.
19 *Id.* at 4-5.

Commission proceeding, including the type of detailed interrogatories, hypotheticals, multi-sub-part questions, or requests for large amounts of data for which parties may actually need two calendar weeks to respond. Here, however, the requested data essentially serve as the workpapers underlying the monthly reports since the reports are built upon the data the IOUs are required to produce. Production of documents akin to workpapers do not require two-week production timelines, especially when PG&E has consistently met its five-day deadline, SCE already meets the five-day deadline without being required to do so, and SDG&E has often provided the data within five days without being required to do so.

The Joint IOUs state: "From a legal perspective, it is unclear why the Commission ordered different reporting requirements for the Joint IOUs."[20] CalCCA imagines the coordination of three different ERRA Forecast proceeding decisions (consolidated with trigger proceedings) over the Thanksgiving holiday last year was a heavy undertaking, especially for Commissioners, judges and staff working remotely due to COVID. Regardless, the Joint IOUs' statement regarding the different reporting requirements is the same issue CalCCA's proposal is trying to address: the resolution of any inconsistencies that may prevent long-term alignment in data production.

II. THE IOUS RESIST A FRAMEWORK THAT HAS WORKED WELL FOR NEARLY 20 YEARS (QUESTION 2)

The IOUs' responses to Question 2 and its sub-parts raise a number of red herrings that should not detract from the merits of CalCCA's proposal. First, the IOUs incorrectly assert the purpose of the proposal is to give "decisionmakers additional access to procurement information."[21] No CCA decisionmaker will have access to confidential procurement

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20 Joint IOUs Response at 5.

21 *Id.* at 8.

information as a result of CalCCA's proposal. The proposal works within the Commission's existing confidentiality framework, which only gives qualified reviewing representatives access to confidential information.[22] The IOUs' misrepresentation of CalCCA's proposal must not influence the Commission's decision-making.

Second, the IOUs suggest adoption of CalCCA's proposal may result in the CCAs somehow gaining a market advantage over the IOUs, having superior market insight compared to the Commission, or causing the first dominoes of another energy crisis to fall.[23] This parade of horribles is full of vague conjecture but empty of merit; the IOUs do not provide any concrete explanations of how a model predicting the direction of the PCIA under different scenarios could result in the erosion of "fundamental customer protections established in the wake of the 2000-2002 energy crisis."[24] Again, the Commission's decision-making should be based on concrete fact and legal argument, and not on speculation or conjecture.

The Joint IOUs ask the Commission to require the CCAs to demonstrate how a reviewing representative can model the PCIA while accomplishing the "nearly impossible task"[25] of ensuring the CCAs not use the results in connection with market transactions. No such requirement is necessary since CalCCA can address the issue now.

The IOUs' "impossible task" is about as difficult as a professional basketball player making a layup during warm-ups. There is almost zero potential for a model showing a range of $/kWh PCIA rates to influence the market price of energy or capacity. The model would not reveal confidential information. It would present a range of possible PCIA rates based on possible market outcomes that an individual user selects, *e.g.*, if brown power prices are *x*, and

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22 CalCCA Opening Comments at 19-22.
23 Joint IOUs Response at 8-9.
24 *Id.* at 8.
25 *Id.* at 9, 11.

retails sales are *y*, then the PCIA would be *z*. This modeling cannot influence the clearing price of a particular Request for Offer or the contract price of a bilateral transaction because it is not possible to discern the price an IOU or another load-serving entity (LSE) is willing to pay for capacity or energy from a $/kWh PCIA forecast. The modeling results are simply too aggregated.

The IOUs' own ERRA Forecast applications, workpapers and testimony demonstrate this fact. In those cases, the forecasted PCIA rates the IOUs propose rely on a great deal of market-sensitive information, but none of the proposed revenue requirements or forecasted PCIA rates are redacted in those pleadings. The reason is that the outputs are too aggregated to be of any value to an unscrupulous party looking to manipulate the market.

CalCCA's proposal builds upon a confidentiality framework that has protected utility data for nearly 20 years. Many of the concerns the IOUs' comments raise, *e.g.*, the IOUs being unsure "if market sensitive data received under a Year-Round NDA is being used for non-approved purposes,"[26] could also occur under the existing framework. However, the market power the IOUs believe could materialize from those circumstances has not materialized because the Commission's confidentiality framework relies on what DACC/AReM deftly calls a "well-drafted agreement," which is all that is required here.[27]

CalCCA's aim is to work with the IOUs and "all affected parties" to develop such an agreement.[28] The IOUs include some proposals to help ensure confidentiality that are worth further consideration, including dispute procedures that would allow the IOU to suspend providing access to someone that has breached the NDA,[29] and to prevent someone that has

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26 Joint IOUs Response at 13.
27 DACC/AReM Response at 3.
28 Joint IOUs Response at 13.
29 *Id.* at 14.

breached the NDA from being a reviewing representative in the future.[30] CalCCA's Opening Comments also include a number of protections that go beyond those the IOUs recommend in their Opening Comments, including an NDA with a one-year term to limit the IOUs obligation in a manner similar to a docket-specific obligation.[31]

CalCCA's Opening Comments also propose a right for Commission Staff to inspect the model and use of confidential information.[32] That approach is superior to the IOUs' "audit right",[33] which would provide the IOUs an unacceptable entrée to review another market participant's proprietary model.[34] This opposition to the IOUs' "audit right" proposal is not hypocritical and, in fact, helps demonstrate the imbalance the IOUs continue to seek for two reasons. First, CalCCA's model has been designed to help forecast PCIA rates charged by the IOUs. It will be used only for information and planning by CCAs who make use of the model. This is a very different set of circumstances than the IOUs seeking access to this planning model, since IOUs do not pay any rates charged by CCAs. Second, where CalCCA seeks to use *reviewing representatives* to review IOU *data*, which directly impacts the PABA balances, the IOUs propose to allow *any IOU personnel* to access the CCAs' *model*. This would give IOUs more flexible access to CalCCA's model than CalCCA has to the IOU data. If the IOUs have concerns regarding whether the model structurally prevents disclosure of confidential information, Energy Division Staff can review the model's use of that information to ensure unauthorized personnel do not have access.

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30 Joint IOUs Response at 14.
31 CalCCA Opening Comments at 19-22.
32 *Id.* at 22.
33 Joint IOUs Response at 13-14.
34 Cal. Civ. Code section 3426.1(d) (defining "trade secret").

III. THE IOUS MISS THE POINT ON CONFIDENTIAL DATA, BUT DACC/AREM'S NDA PROPOSAL HAS MERIT (QUESTION 3)

A. Systemic Misapplication of D.06-06-066 is the Problem.

With regard to the treatment of confidential data, the IOUs' Opening Comments miss the point, arguing about the symptoms of a problem rather than the problem itself. The inconsistent treatment of data among IOUs is the symptom of an on-going, systematic misreading of the appendices to D.06-06-066 defining what data should be made public. CalCCA's proposal is not consistency for the sake of consistency, it is a proposal to make public what D.06-06-066 requires the IOUs to make public within their ERRA Forecast proceedings. The IOUs' arguments about the actions of one IOU binding another, [35] or one IOU's willingness to disclose certain data based on circumstances distinct to that IOU, [36] miss the point. Tables 1 and 2 in CalCCA's Opening Comments demonstrate the incorrect application of the D.06-06-066 confidentiality standards pertaining to data requested and reviewed by the CCA reviewing representatives – the inconsistency is how that misapplication manifests.

The IOUs' exaggeration of the differences between their service territories and bookkeeping should be given little weight. After years of participating in the ERRA Forecast proceedings, the CCAs' reviewing representatives know the IOUs' workpapers well, and there is little difference between the level of confidentiality provided. The data in those workpapers are simple: generation resources, forecasted loads, quantities, costs and revenues. It is not as though a dollar in SCE's service territory is more confidential than a dollar in PG&E's service territory.

A consistent interpretation of the same decision across the IOUs' ERRA Forecast proceedings should be the default; but that does not mean exceptions should not apply. For

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[35] Joint IOUs Response at 15.

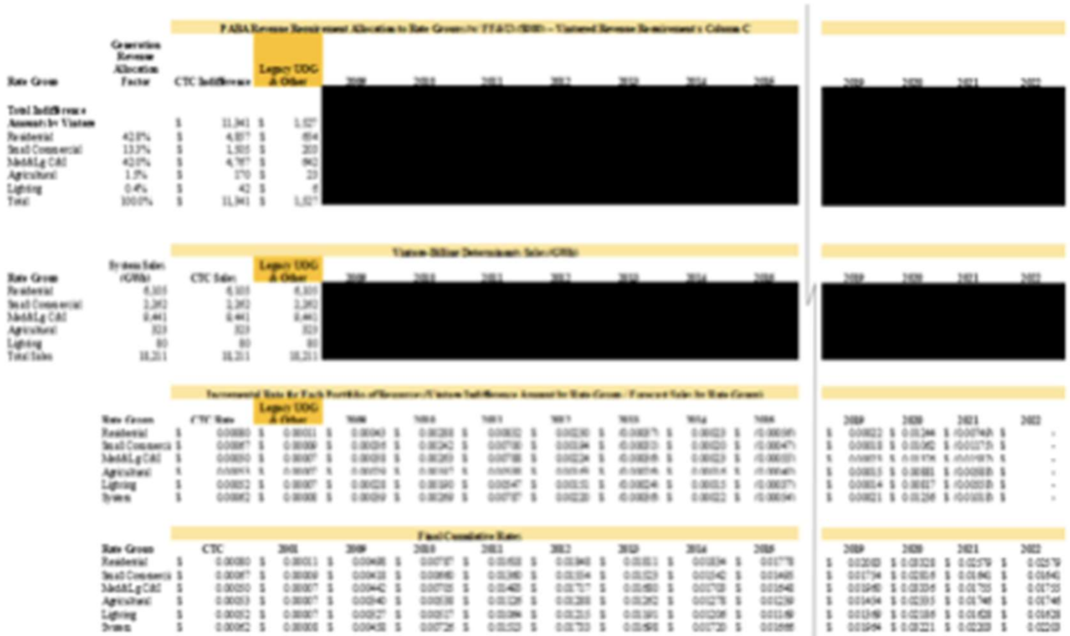
[36] *Id.* at 15.

example, the first three rows of Table 1 from CalCCA's Opening Comments (reproduced below) show that SDG&E keeps confidential data that should be made public:

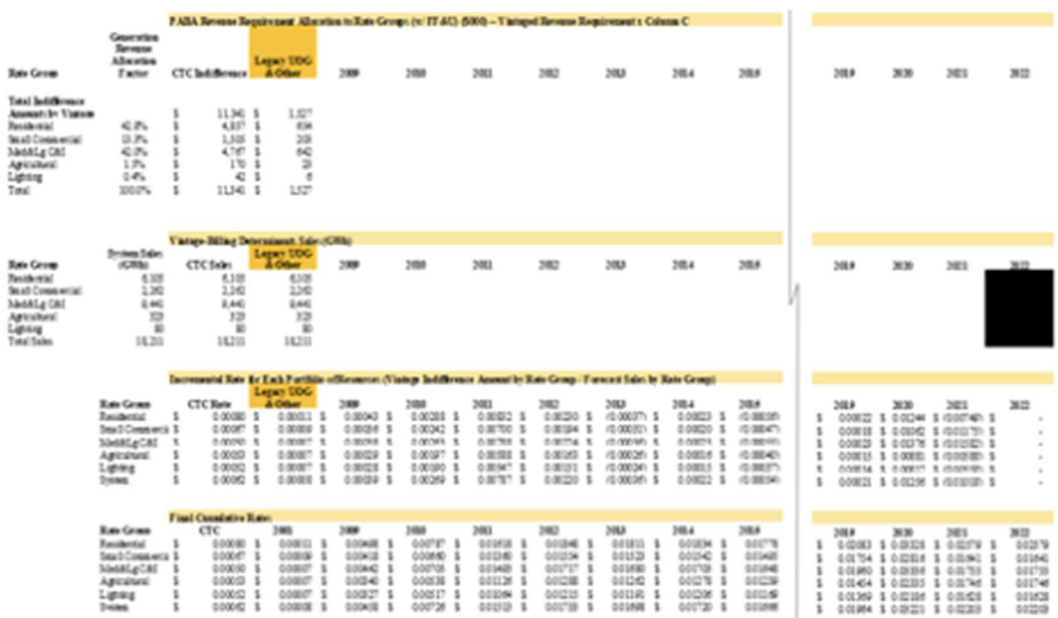
ERRA Proceeding	Data Category	D.06-06-066 Matrix	PG&E	SCE	SDG&E
Forecast	PCIA Portfolio Cost by Vintage	Section II.B.8	Public	Public	Confidential
Forecast	GRC Revenue Requirement by Vintage	Section III.A	Public	Public	Confidential
Forecast	Total PCIA/PABA Revenue Requirement by Vintage	Section III.A & III.B	Public	Public	Confidential

Redacting data that would allow parties to reverse engineer confidential data is a valid exception to the default rule of disclosure, but the exception does not warrant keeping the totality of all vintages of PCIA portfolio costs, GRC revenue requirements, and PCIA/PABA revenues redacted, which is SDG&E's current practice. One SDG&E argument against making the data referenced above public in the past has been that if the revenue requirement and customer sales by vintage are unredacted, parties would be able to discern bundled customer sales volumes (i.e. SDG&E's bundled sales forecast). However, the same protection for bundled customer sales volumes can be achieved by redacting only a subset of the PCIA rate inputs rather than all inputs. For example, to avoid disclosing its bundled customer sales volumes, SCE only redacts sales volumes for the last PCIA vintage. Other data in SCE's PCIA template, including the items listed above, remain unredacted. Excerpts from SDG&E's public workpapers filed with its 2022 ERRA Forecast are provided to illustrate.

SDG&E Indifference Rate Calculation as Filed



Alternative SDG&E Redaction



The default data treatment should be to follow the matrix unless reasonable exceptions apply, and then those exceptions should be applied as narrowly as possible.

B. DACC/AReM's Proposal for a "Modified NDA" Has Merit and Should Be Considered in a Future Phase of This Proceeding.

DACC/AReM recommend the Commission adopt two NDAs—one more stringent than the other—to govern access to confidential PCIA-related data.[37] Under the DACC/AReM proposal, the more stringent NDA would conform to the Commission's model NDA[38] and would govern and enable access to data associated with individual contracts and ongoing ERRA and PABA detail.

The second, "modified NDA" would include less onerous restrictions (consistent with the Phase 1 NDA approved in this proceeding in December 2017[39] (Phase 1 NDA)). The modified NDA would govern and enable access to certain data used to calculate the PCIA (for example, sales volume by vintage) but not to detailed contract information.[40] DACC/AReM suggest that this two-tier structure would allow a broader set of reviewing representatives to "view basic data that can be used to understand, explain and forecast each IOU's PCIA without being exposed to market-sensitive contract information."[41] To strike a balance between transparency and ensuring that market participants do not use the confidential data to gain an unfair advantage, DACC/AReM suggest that "[i]ndividuals who do not work for or consult to market participants

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37 DACC/AReM Response at 5.

38 D.08-04-023, *Decision Adopting Model Protective Order and Non-Disclosure Agreement, Resolving Petition for Modification and Ratifying Administrative Law Judge Ruling* (Apr. 10, 2008).

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

40 DACC/AReM Response at 5.

41 *Id.*

on wholesale power issues could sign this [modified] NDA, even if other individuals in the firm might not [?] (*sic*) do so."[42]

DACC/AReM's proposal is generally reasonable and worth exploring. The CCAs, the IOUs and other parties negotiated, and the Commission approved the Phase 1 NDA to ease the restrictions on reviewing representatives in the Commission's model NDA. The Phase 1 NDA, however, applies only to this proceeding. Adopting a modified NDA similar to the Phase 1 NDA that applies beyond this proceeding might allow key stakeholders, including CalCCA,[43] to access more of the data necessary for CCA rate forecasting and financial planning. Such modifications, coupled with the requirements for an ethical wall and other strict protections, would help staff at CalCCA and CCAs better anticipate changes in the PCIA over time without the need for reviewing representatives. This in turn would reduce CCA customers' vulnerability to unpredictable swings in rates as a result of PCIA volatility.

While CalCCA continues to recommend that the Commission require the utilities to make confidential data available year-round (subject to the protections in the Commission's model NDA)[44], DACC/AReM's proposal for the development and adoption of a modified NDA merits future consideration, perhaps in the next phase of this proceeding.

IV. THE JOINT IOUS' PROPOSAL TO CREDIT YEAR-END BALANCES VIA PABA SHOULD BE APPROVED (QUESTION 4)

The IOUs advocate for the adoption of transferring year-end balancing account balances to the most recent vintage as a default approach, with transfers to different vintages being

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42 *Id.*

43 The CCAs acknowledge that the IOUs' concerns about widespread dissemination of market-sensitive materials are valid, and have recommended that only representatives of organizations representing customers that pay the PCIA should have access to this data (and only to the extent those representatives are willing to sign an NDA). *See* CalCCA Opening Comments at 19.

44 *See* CalCCA Opening Comments at 20.

warranted in "some unique circumstances"[45] They also acknowledge CalCCA's prior point that "[a]ny default rule should apply to both under- and over-collections." [46]

The IOUs have it right on this point. Establishing a default rule will provide certainty,[47] and exceptions, in particular for errors that require prior-period adjustments, should be allowed.[48] Allowing for those exceptions to be proposed and, if necessary, litigated in ERRA proceedings also makes sense. [49] CalCCA urges the Commission to adopt this proposal.

PG&E also includes a paragraph in the Joint IOUs' comments changes to the default rule that may be warranted on account of its 2020 Phase 2 GRC.[50] While CalCCA remains open to modifications to PCIA-related accounting that improve accuracy, any change to the default rule applicable to all IOUs should occur via this proceeding, or other generally applicable PCIA rulemakings that may follow this proceeding, rather than be litigated via the already condensed and over-burdened ERRA proceedings.

V. THE UTILITIES MUST MAKE CLEAR HOW BUNDLED CUSTOMERS' SHARE OF PABA CREDITS ARE CALCULATED (QUESTION 5).

The CCAs had hoped the IOUs' Opening Comments would make clear how bundled customers' share of PABA balances would be calculated when they are applied to ERRA balances, a step that all parties agree is necessary to avoid unnecessary ERRA triggers. Since all customers owe the PABA balance, overcollections that are owed to customers must be split between bundled and unbundled customers. It is important for the IOUs to provide the details of this accounting so that stakeholders can understand how the IOUs determined the bundled customer portion of the

45 Joint IOUs Response at 16.
46 *Id.* at 16.
47 *Id.* at 17.
48 *Id.*
49 *Id.*
50 *Id.* at 18.

PABA balance. The CCAs are not requesting any new work from the IOUs, other than the *de minimis* effort entailed in their existing ERRA and PABA balance reports the combined ERRA and PABA balance, that they will have to calculate anyway, along with the working formulae that will show how each IOU determined bundled customers' share of the PABA.

VI. CONCLUSION

For all the foregoing reasons, and those stated in Opening Comments, CalCCA respectfully renews its request for the Commission to:

- Align the data requirements, including the master data request approach and five-day timeline, approved last year in the ERRA Forecast proceedings to ensure long-term implementation of those requirements is consistent across the service territories;

- Develop a non-docket specific NDA to provide the data the CCAs require year-round in order to protect their customers is as follows:

  - The *same* confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission;

  - The *same* data and workpapers underlying those Monthly Reports, at the *same* level of granularity, and within the *same* schedule, that is now required to be provided as part of ERRA forecast proceedings in each IOU service territory; and

  - Continued access to the *same* workpapers underlying PCIA rates that the IOUs have provided within the prior years' ERRA Forecast proceedings as part of either the November Update or an advice letter implementing the final decision in the ERRA Forecast proceeding;

- Require correct and consistent application of D.06-06-066 with regard to confidential data as a default, with any exceptions narrowly applied;

- Adopt a default approach of refunding or charging over- and under-collections via the most recent PABA vintage for year-end balances, including PG&E's PCIA Undercollection Balancing Account Financing Subaccount; and

- Require the IOUs to detail how they derive bundled customers' share of the PABA balance when combining it with the ERRA balance to avoid unnecessary ERRA triggers.

Respectfully submitted,

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On behalf of
California Community Choice Association

October 8, 2021

Submit comment on September 27-28 Stakeholder Call Discussion

2021-2022 Transmission planning process

1. Provide your organization's comments on the overview and key issues, as described in slides 4-16 of the ISO's day 1 presentation:

No comments at this time.

2. Provide your organization's comments on the preliminary reliability assessment results for the northern areas, as described in slides 17-118 of the ISO's day 1 presentation:

No comments at this time.

3. Provide your organization's comments on the high voltage assessment results for the PG&E area, as described in slides 119-143 of the ISO's day 1 presentation:

No comments at this time.

4. Provide your organization's comments on the preliminary reliability assessment results for the southern areas, as described in slides 144-220 of the ISO's day 1 presentation:

No comments at this time.

5. Provide your organization's comments on the preliminary reliability assessment results for the VEA areas, as described in slides 221-232 of the ISO's day 1 presentation:

No comments at this time.

6. Provide your organization's comments on the preliminary reliability assessment results for the SDG&E areas, as described in slides 233-253 of the ISO's day 1 presentation:

No comments at this time.

7. Provide your organization's comments on the wildfire assessment scenarios, as described in slides 254-261 of the ISO's day 1 presentation:

No comments at this time.

8. Provide your organization's comments on the updates related to the 20-Year Transmission Outlook, as described in slides 262-281 of the ISO's day 1 presentation:

CalCCA reiterates its appreciation from previous comments on the CAISO's efforts to develop the 20-year Transmission Outlook and commends the CAISO for its collaboration with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) in the IRP, SB 100, and Integrated Energy Policy Report (IEPR) processes.[1] Coordination with these processes will ensure resource procurement and new transmission build aligns. Forward planning with a long enough lead time will be critical in ensuring the state is prepared to meet SB 100 goals that require renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045. The CAISO should consider how the 20-year Transmission Outlook could be incorporated into the existing Transmission Planning Process (TPP) to consider what transmission build will need to occur and in what timeframe to meet policy goals. Given the time required to develop new transmission, the 10-year look ahead in the TPP can result in transmission projects coming online just in time to meet an identified reliability need.

CalCCA is encouraged that the 20-year Transmission Outlook will utilize the Starting Point scenario based off the SB 100 Core scenario for 2040. Recognizing that decarbonization goals necessitate significant resource build, it is prudent to use this scenario to inform potential transmission projects so that new clean resources do not get stranded behind transmission constraints. Considering the large number of resources expected to come online to meet state policies, the TPP could benefit from the insight of a longer planning horizon provided by the 20-year Transmission Outlook to inform policy-driven transmission projects. The 20-year Transmission Outlook should be used to inform the TPP of transmission needs driven by clean energy policies like SB 100 so that projects approved in the TPP also contribute to meeting policy goals that will be realized beyond 10 years out.

CalCCA also supports the 20-year Transmission Outlook's consideration of key environmental and land use impacts provided by the CEC. It may be valuable for the CAISO and the CEC to incorporate such impacts to the normal TPP cycle as well. Land use and habitat concerns can create serious delays or project cancellations if not incorporated into site evaluation from the start. By incorporating these considerations into transmission planning, the CAISO, the Commission, and the CEC can help steer projects to less sensitive areas and avoid potentially serious delays or cancellations of transmission projects needed to integrate future resource procurement.

9. Provide your organization's comments on the PG&E Reliability Alternatives:

No comments at this time.

10. Provide your organization's comments on the SCE Reliability Alternatives:

No comments at this time.

11. Provide your organization's comments on the SDG&E Reliability Alternatives:

No comments at this time.

12. Provide your organization's comments on the GLW Reliability Alternatives:

No comments at this time.

13. Provide your organization's comments on the economic assessment update, as described in slides 1-9 of the ISO's day 2 presentation:

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[1] CalCCA Comments on July 27, 2021 Transmission Planning Stakeholder Call, August 10, 2021.

No comments at this time.

14. Provide your organization's comments on increasing procurement and capacity in portfolios topic, as described in slides 10-14 of the ISO's day 2 presentation:

CalCCA generally supports the CAISO's intention to consider additional upgrades beyond those identified in the analysis for this planning cycle but requests additional clarification on how such upgrades will be selected. The CAISO's presentation indicates that it intends to consider additional upgrades to reflect the increase in resource procurement and provide flexibility for resources not currently in the base portfolio.[2] Transmission and resource build are inextricably linked and identifying additional upgrades now in anticipation of increased resource build could provide the necessary signals to resources as to where to site new resource build necessary to meet resource procurement targets and SB 100 goals. CalCCA looks forward to additional discussion on this topic in future stakeholder calls.

15. Additional comments on the September 27-28, 2021 stakeholder call discussion:

No comments at this time.

[2] CAISO Day 2 Presentation at 12.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN

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October 11, 2021

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- Conduct workshops exploring the inconsistencies between the 38 million metric ton (MMT) PSP Core Portfolio and stakeholder models and analyses;
- Initiate a process within the IRP proceeding to determine a target loss of load expectation (LOLE) and resulting planning reserve margin (PRM);
- Reject the CAISO's recommendation to accelerate the MTR Decision procurement; and
- Improve and refine the process and standards for LSE Plan filings.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN

The California Community Choice Association[1] (CalCCA) submits these Reply Comments in response to the *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan* (PSP Ruling), issued on August 17, 2021.

I. INTRODUCTION

CalCCA appreciates the opportunity to provide these reply comments. The considerable time and effort put forth by the California Public Utilities Commission (Commission) staff in devising the Preferred System Plan (PSP) recommendations, as well as the extensive comments and modeling provided by stakeholders in response to the PSP Ruling, all contribute to a robust record to evaluate the PSP.

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Several parties including Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E) and the California Independent System Operator (CAISO) provided their own modeling analysis along with their opening comments. The input assumptions of each can vary widely resulting in very different results. Examining different assumptions and the resulting portfolios is a beneficial process if given sufficient time for parties to understand and evaluate the efficacy of the modeling performed. Given the opportunity for the Commission to utilize and potentially incorporate the valuable data provided by Commission staff and stakeholders into the PSP, the Commission should order workshops to discuss and consider the suggested inputs, assumptions and results set forth in the PSP Ruling and stakeholder's opening comments. Such workshops will provide an opportunity for the Commission to refine its results to ensure an accurate PSP.

In response to opening comments from stakeholders in this proceeding, the Commission should:

- Clarify the overlap of the Integrated Resource Plan (IRP) individual plan filings of each load-serving entity (LSE Plans) and the Mid-Term Reliability Decision (MTR Decision);[2]
- Conduct workshops exploring the inconsistencies between the 38 million metric ton (MMT) PSP Core Portfolio and stakeholder models and analyses;
- Initiate a process within the IRP proceeding to determine a target loss of load expectation (LOLE) and resulting planning reserve margin (PRM);
- Reject the CAISO's recommendation to accelerate the MTR Decision procurement; and
- Improve and refine the process and standards for LSE Plan filings.

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[2] *Decision Requiring Procurement to Address Mid-term Reliability (2023-2026),* D.21-06-035 (June 24, 2021) (MTR Decision).

II. THE COMMISSION SHOULD CLARIFY THE OVERLAP OF THE LSE PLANS AND THE MTR DECISION

CalCCA requested in its opening comments that the Commission confirm that in combining the aggregated individual LSE Plans with the procurement order in the MTR Decision, to the extent the LSE plans contain excess capacity from the Decision (D.) 19-11-016 requirements, there may be overlap between the MTR Decision requirements and what is already in the LSE Plans.[3] Therefore, the Commission should confirm that the full 11.5 net qualifying capacity (NQC) gigawatts (GW) from the MTR Decision is not layered on top of the LSE Plans, but that the excess procurement above D.19-11-016's requirements within an LSE's Plans can be counted towards the 11.5 NQC GW requirements, if applicable. To that end, CalCCA questions PG&E's modeling input recommended in its proposed PSP that would "remove incremental resource additions from the 2020 LSE aggregated plans" and "update resources related to MTR procurement to better align with the MTR Decision."[4] Instead, the Commission should identify any overlap and adjust the portfolio accordingly.

III. THE COMMISSION SHOULD CONDUCT WORKSHOPS EXPLORING THE INCONSISTENCIES BETWEEN THE 38 MMT PSP CORE PORTFOLIO AND THE STAKEHOLDER MODELS AND ANALYSES

CalCCA appreciates the significant work that went into the Commission's modeling for the PSP, as well as the contributions of modeling analysis and/or results by SCE, PG&E[5] and the CAISO.[6] In addition, the analysis provided by other stakeholders of the Commission's modeling

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[3] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* R.20-05-003 (Sept. 27, 2021) (CalCCA's Opening Comments) at 3-4. Opening Comments of all other parties cited herein will be referred to by party name.

[4] *PG&E Opening Comments* at 7.

[5] PG&E proposed a portfolio based on preliminary modeling, which it states it will update in its Reply. *Id.* at 8, fn. 10.

[6] CAISO provided modeling conclusions, but the link provided with modeling results and outputs was outdated and the CAISO informed CalCCA that the modeling results and outputs are not yet available. *CAISO Opening Comments* at 2.

also informs the IRP process. As PG&E correctly noted in its opening comments, "through the collective effort of the entire group the IRP process is improved with improved analytics to better inform future procurements aligned with the IRP process and to avoid other out-of-cycle procurement requirements."[7] As explored below, the inconsistencies in the current modeling and analysis of the Commission and stakeholders should be addressed prior to the adoption of a PSP. Given the opportunity to finely tune the PSP with the input of Commission staff and stakeholders, the Commission should hold one or more workshops to collectively analyze the assumptions, analysis, results, and proposals of stakeholders in their Opening Comments and modeling as compared to Commission staff's modeling and analysis. After the workshops, the Commission can incorporate information gleaned from the workshops into any re-runs of the modeling and a decision regarding the PSP, and into future IRP planning.

A. Stakeholder Modeling Input and Assumption Inconsistencies Reflect the Lack of Predictability and Transparency in IRP Planning Standards

Stakeholder comments reflect differing approaches taken on the inputs and assumptions to inform the preferred portfolio, all of which deserve further analysis given the lack of predictable standards and transparency at the outset of the planning process. Modeling assumptions including the load forecast basis (including "load adders" or modifiers), integration of the procurement ordered by the MTR Decision, predicted thermal generation retirements, import assumptions, LOLE target, PRM, Effective Load Carrying Capacity (ELCC) methodology and other inputs informed the Commission's modeling, as well as the modeling of SCE, PG&E and the CAISO. Given the recent emergency procurement orders signaling the need for better IRP long-term planning, the Commission should hold one or more workshops at which all modeling and analysis of the stakeholders can be considered.

[7] *PG&E Opening Comments* at 1-2.

Commission staff provided substantial explanation regarding its process in adopting the 38 MMT Core Portfolio. However, the inputs and assumptions on which the sensitivities and the proposed PSP portfolio are based are not clear, are in some cases not substantiated, and are also extensively questioned by parties in opening comments.[8] First, with respect to the load forecast, while many parties including The Public Advocates Office (Cal Advocates), California Energy Storage Alliance (CESA), Green Power Institute (GPI), PG&E and SCE advocate for the use of the 2020 (rather than the 2019) Integrated Energy Policy Report (IEPR) forecast in the PSP,[9] what Commission staff actually used as a forecast basis is unclear. For example, while the 38 MMT Core Portfolio is based on changes to the Renewable Energy Solutions Model (RESOLVE) modeling, including adding "load adders" to account for the managed peak impact of the 2020 CEC IEPR Report demand forecast (instead of 2019), all other scenarios analyzed by the Commission in RESOLVE utilize the demand forecast from the CEC's 2019 IEPR.[10]

Second, consistent with CalCCA's opening comments, many parties questioned the use of the 22.5 percent PRM past 2026, given Commission staff's findings that with the 22.5 percent PRM, the LOLE in 2026 is 0.064, and in 2030 is 0.054, both substantially below the 0.1 standard.[11]

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8 *See Green Power Institute Opening Comments* at 9 (recommending that Commission staff provide "a grid/table that lists respective inputs and assumptions for each sensitivity in columns for each parameter (e.g., PRM, load forecast, forced capacity, thermal retirements) . . . to clarify what forecast, PRM and other inputs are driving the differences between each sensitivity").

9 *Cal Advocates Opening Comments* at 2; *CESA Opening Comments* at 9-10; *GPI Opening Comments* at 9; *PG&E Opening Comments* at 7; *SCE Opening Comments* at 6.

10 *See* PSP Ruling at 13-14 (discussing "load adders" added to the RESOLVE modeling to account for the managed peak impact of the 2020 IEPR demand forecast (instead of 2019) and the high electrification scenario (instead of the mid-case)); *see also id.* at 14 ("[u]nless otherwise noted, all scenarios utilized the demand forecast from the CEC's 2019 IEPR").

11 *See* PSP Ruling at 20; *see also CalCCA Opening Comments,* at 5-6; *PG&E Opening Comments* at 10 (stating that the 2026 and 2030 LOLE for the 38 MMT Core Portfolio are "much lower than a typical electric planning standard of 0.1 LOLE that is industry standard nationwide"); *SCE Opening Comments* at 11-13 (SCE's study results of the 38 MMT Core Portfolio demonstrate "a portfolio with new resource additions that far exceed industry standards for reliability and therefore are more expensive than necessary," and recommending that the Commission "assess whether it is appropriate to reduce the PRM

The 22.5 percent PRM was adopted despite the MTR Decision specifically stating that more analysis is necessary before adopting any long-term PRM.[12]

Third, CalCCA agrees with the City and County of San Francisco (CCSF) and the Bay Area Municipal Transmission Group (BAMx) that the Commission should incorporate updated transmission cost information in its 38 MMT Core Portfolio from the 2021-2022 TPP, available in November 2022, before adopting the 38 MMT Core Portfolio as the reliability and policy-driven base case for the 2022-2023 TPP.[13]

Fourth, the Commission should provide additional information regarding its ELCC calculations for the MTR Decision and for its 38 MMT Core Portfolio. SCE questions the use of the ELCC methodology in RESOLVE (and uses its ABB portfolio to estimate expected capacity of variable resources in its modeling).[14] Additional analysis and stakeholder input should be conducted regarding the proper input regarding the contribution of variable resources which could significantly impact the PSP.

B. Significant Modeling Result Discrepancies Between Commission Staff and Stakeholders Requires Further Analysis

With respect to parties who performed modeling in addition to Commission staff's modeling, the results and recommendations vary substantially. SCE provided its modeling data and results, while PG&E and CAISO provided results but no data to support the results. The

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after the MTR resources are to come online (i.e., after 2026) to a level more in line with established reliability criteria"); *City and County of San Francisco Opening Comments* at 3-4 (extending the 22% PRM "for the entire ten-year planning period will result in over building and unnecessary costs; it may also result in a PSP portfolio resource mix that is less cost-effective than what may be needed to maintain reliability"); *Alliance for Retail Energy Markets Opening Comments*, at 3-8 (opposing the use of the 22.5 percent PRM as the long-term planning standard); *Calpine Corporation Opening Comments* at 2 ("Calpine is concerned that the 38 MMT Core Portfolio yields better than 1-in-10 reliability for 2026, even assuming that long lead time procurement is deferred until 2028).

12 MTR Decision at 22.

13 *See CCSF Opening Comments* at 5; *BAMx Opening Comments* at 2-5.

14 *SCE Opening Comments* at 9-10.

following is a brief recap of the modeling results, which indicate further analysis and comparison to Commission staff modeling would provide valuable input to inform the Commission's decision on the PSP.

SCE's capacity expansion and reliability modeling of the Commission's 38 MMT Core Portfolio, with some changes to the inputs compared to Commission staff's input into its models,[15] resulted in a LOLE of zero.[16] SCE therefore recommends the removal of between 3,500 MW and 5,500 MW of energy storage from the 38 MMT Core Portfolio by 2030, and that the Commission should not issue any additional reliability-based procurement in excess of the MTR Decision at this time. In fact, SCE's modeling indicates that the excessive resource additions required by the 38 MMT Core would come at a cost to consumers of at least $450 million per year in 2030.[17]

PG&E, on the other hand, proposes an alternative PSP to the 38 MMT Core Portfolio based on its preliminary modeling, which would result in over 10,000 less MW (nameplate) by year 2030.[18] PG&E disagrees with Commission staff's use of the 2019 IEPR forecasts and the 2020 aggregated LSE plans (which it states are outdated). PG&E also states that the methodology used to develop the 38 MMT Core Portfolio results in a portfolio larger than needed and misaligned with the MTR Decision, and that the 38 MMT Core Portfolio fails to

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15 Specifically, SCE directly applied the 2020 IEPR load forecast to determine the energy need and 22.5 percent PRM requirement based on the managed load peak, consecutive years 2022 to 2030 were modeled (and not 2030-2032), and instead of the Commissions ELCC methodology the expected energy during the managed load peak hour for each month was used to determine solar and wind resource contribution. *Id.* at 6-7.

16 SCE independent modeling analyses on the 38 MMT Core Portfolio used the ABB CE Model and evaluated the operational feasibility with PLEXOS PCM and calculated the LOLE to evaluate the portfolio's reliability performance. *Id.* at 5, and Appendices A and B (modeling results).

17 *Id.* at 5.

18 *PG&E Opening Comments* at 6-10.

consider zonal and local resource requirements.[19] Changes in the inputs to the portfolio were therefore made by PG&E to: (1) update the load forecast to reflect the most recent CEC 2020 IEPR forecast and 2020 IEPR high EV scenario; (2) remove incremental resource additions from the 2020 LSE aggregated plans; and (3) update the resources related to MTR procurement to better align with the MTR decision.[20] After finding that its proposed portfolio requires less nameplate capacity than the 38 MMT Core Portfolio, PG&E also suggests that additional capacity may need to be added to account for uncertainties related to extreme weather.[21]

Finally, CAISO's production cost modeling determined that Commission staff's 38 MMT Core Portfolio meets the 0.1 LOLE standard, but provides only 500 MW of effective capacity above the level necessary to the 0.1 LOLE in 2026.[22] The full analysis and results of this modeling are not available as of the time of this writing, so CalCCA cannot opine on them.

Given the differing modeling results among Commission staff, SCE, PG&E and the CAISO, a discussion and analysis of the inputs, assumptions and results involving all stakeholders would be useful to inform the adoption of the PSP.

C. The Commission Should Hold One or More Workshops with Stakeholders to Review and Compare Modeling Assumptions and Conclusions

To ensure accurate planning both in this IRP cycle and moving forward and to avoid additional emergency procurement orders to address shortfalls, the Commission should utilize this opportunity to analyze and refine the inputs, assumptions and results of the modeling with stakeholder input. Given the differing inputs, assumptions, results and the lack of current availability of data related to two potentially informative models (PG&E and CAISO), and the

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19 *Id.* at 7.
20 *Id.*
21 *Id.* at 9.
22 *CAISO Opening Comments* at 2.

significant questions regarding inputs by Commission staff including the appropriate load forecast and PRM, CalCCA strongly recommends that the Commission order one or more workshops to allow staff and stakeholders to collectively study all of the available information.

IV. THE COMMISSION SHOULD INITIATE A PROCESS WITHIN THE IRP PROCEEDING TO DETERMINE A TARGET LOLE AND RESULTING PRM

As set forth above regarding the input of the 22.5 percent PRM into Commission staff's modeling for the PSP, CalCCA is concerned that the Commission has failed to adequately study and establish a target LOLE and resulting appropriate PRM. Commission staff changed its RESOLVE modeling for the PSP to align the PRM "with the 2024 "high need" scenario *adopted* in D.21-06-035, which uses a PRM of 22.5%."[23] However, the Commission in the MTR Decision did not *adopt* the "high need" PRM of 22.5 percent for the long term, and even noted that "[m]ore analysis is needed before revising the [PRM] for long-term planning in the IRP proceeding on a permanent basis."[24] As CalCCA has stated previously, extensive analysis is required to construct the PRM:

> A PRM should be calculated using a robust stakeholder process, employing the following high-level steps. First, decide on a "target" of grid reliability that can be achieved at a reasonable cost. Historically, this has been one loss-of-load event every ten years (often referred to as "0.1 LOLE," which is a count of the expected number of loss-of-load events in a given year). However, the CPUC may want to revisit this number (and the underlying weather and load data) to account for climate change or affordability impacts, as well as the increased renewable and battery penetration in the grid relative to when the 0.1 target was first established. Second, calculate the amount of generating resources that are required to achieve this target using a production cost model. Third, divide that amount by the load forecast, incorporating an operating reserve margin adder. The result will be the PRM that should be used.[25]

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[23] PSP Ruling at 13 (emphasis added).

[24] MTR Decision at 86, Finding of Fact 1.

[25] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements,* R.20-05-003 (Mar. 26, 2021), Appendix A, at A-2.

Given the substantial impact the PRM has on modeling analysis, CalCCA supports the comments of Alliance for Retail Energy Markets (AReM),[26] CCSF,[27] GPI,[28] PG&E,[29] and SCE[30] recommending that the Commission further evaluate and even initiate a separate process, with robust stakeholder involvement, to establish a target LOLE and resulting PRM.

V. THE COMMISSION SHOULD REJECT CAISO'S RECOMMENDATIONS REGARDING ACCELERATION OF PROCUREMENT

In response to Question 15 regarding whether and how much procurement required in the MTR Decision should be accelerated to 2023, and/or regarding suggesting additional actions to facilitate the additional resources in response to the Governor's Proclamation from July 30, 2021, the CAISO provides its proposals from the Emergency Reliability proceeding, Rulemaking (R.) 20-11-003, to accelerate procurement in 2022 and 2023: (1) set an additional resource adequacy requirement to meet the new demand peak period with a sufficient reserve margin, and (2) increase the existing PRM from 15 percent to 17.5 percent at a minimum.[31] CalCCA previously responded to the CAISO's proposals in the Emergency Reliability proceeding.[32] Specifically, CalCCA has stated its support for procurement mechanisms in which LSEs make best efforts to procure supply side resources to support summer reliability in 2022 and 2023.[33] In

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26 *AReM Opening Comments* at 3-6.
27 *CCSF Opening Comments* at 3-4.
28 *GPI Opening Comments* at 9.
29 *PG&E Opening Comments* at 10
30 *SCE Opening Comments* at 4-6.
31 *CAISO Opening Comments* at 6 (citing Opening Testimony of the California Independent System Operator Corporation, *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021,* R.20-11-003 (Sept. 1, 2021)); *Opening Brief of the California Independent System Operator Corporation*, *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021,* R.20-11-003 (Sept. 20, 2021) at 8-9.
32 *See Reply Testimony of Marie Y. Fontenot on Behalf of the California Community Choice Association,* R.20-11-003 (Sept. 10, 2021) at 3-5; *California Community Choice Association Opening Brief,* R.20-11-003 (Sept. 20, 2021) at 3-6; *California Community Choice Association Reply Brief,* R.20-11-003 (Sept. 27, 2021) at 2-4.
33 *Id.*

fact, CalCCA and other LSEs have demonstrated efforts already underway to expedite procurement to the extent possible above existing procurement mandates to support summer reliability.[34] However, also highlighted by CalCCA and many other parties in the Emergency Reliability proceeding are the many challenges with expediting procurement under such narrow timeframes.[35] CalCCA supports a best efforts standard, without penalties, given the uncertainty around how much additional supply is available or can be accelerated to come online on an expedited basis.[36]

With respect to CAISO's proposals, while LSEs should make best efforts to bring new resources to the balancing authority equivalent to a 17.5 percent PRM with resources available at net peak, CalCCA has cautioned the Commission against making modifications to the Resource Adequacy (RA) requirements due to potential negative consequences associated with adopting new RA requirements under such a short timeframe.[37] In particular, such modifications may increase penalties and associated customer costs without any certainty that incremental supply will be available for LSEs to procure to meet the accelerated requirements despite best efforts.[38]

CalCCA's opening comments in this proceeding highlight the substantial efforts already made by CCAs to aggressively procure new resources, some of which are scheduled to come online in 2022 and 2023 above and beyond requirements set forth in D.19-11-016.[39] CalCCA does not support the imposition of penalties for existing or any new procurement orders or any

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[34] *See CalCCA Opening Comments* at 16-17; *see also Direct Testimony of Lauren Carr, Fred Taylor-Hochberg, and Marie Y. Fontenot on Behalf of California Community Choice Association,* Chapter 1 (Sept. 1, 2021), 3:20-4:3; *California Community Choice Association Opening Brief,* R.20-11-003 (Sept. 20, 2021) at 6-8.

[35] *See California Community Choice Association Opening Brief,* R.20-11-003 (Sept. 20, 2021) at 8-10.

[36] *See id.*

[37] *See id.* at 3-6.

[38] *Id.*

[39] *CalCCA Opening Comments* at 16.

additional acceleration of mandated procurement. As pointed out in opening comments, LSEs need sufficient flexibility to pivot based on market circumstances, and potential issues outside of the control of LSEs, including delays resulting from the backlogged CAISO interconnection queues.

VI. THE COMMISSION SHOULD IMPROVE AND REFINE THE PROCESS AND STANDARDS FOR LSE PLAN FILINGS

The PSP Ruling details the process for aggregating the individual LSE Plans. CalCCA appreciates the painstaking process conducted by Commission staff to iterate the individual LSE Plans. This process included six re-submission requests from September 2020 through February 2021 to correct and clarify information provided by LSEs.[40] To streamline the process and ensure accurate information is provided at the outset by LSEs, recommendations are provided below to update the process and refine the standards and requirements for the filings.

First, and as discussed above, as part of an IRP planning standards stakeholder process, the Commission should develop specific and clear reliability planning standards for individual LSE Plan filings that are grounded in the reliability metric that will be used to evaluate the aggregated portfolio's reliability as a whole. CalCCA agrees with the parties that recommend the Commission "initiate the quantitative work" that will be required to establish robust and consistent planning and reliability standards because this work will help prevent future shortfalls in the aggregated portfolio.[41]

Second, for the years in which LSEs file their LSE Plans, the Commission should formally adopt and finalize all planning standards, inputs, and assumptions nine months before the filing deadline. The modeling required to complete the individual LSE Plans requires

40 PSP Ruling at 4.

41 *GPI Opening Comments* at 5-6; *SCE Opening Comments* at 4.

significant time to complete, and therefore stable and final standards, inputs and assumptions will guide standardized filings by all LSEs.

Finally, the Commission should test and finalize all data templates at least three months prior to the filing date. Templates have been changed based on issues arising during the filing and frequency asked questions process, creating confusion and inconsistencies in the filings. Any required changes need to be identified before the finalization of the templates. Before the Commission finalizes its data templates, a draft version of the templates should be issued, with an opportunity provided to LSEs to test and informally comment on the templates' functionality.

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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General Counsel to the
California Community Choice Association

October 11, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed January 31, 2019)

COMMENTS OF MARIN CLEAN ENERGY ON
PROPOSED DECISION ON INCENTIVE LAYERING, THE WILDFIRE AND NATURAL DISASTER RESILIENCY REBUILD PROGRAM, DATA SHARING, RATE ADJUSTMENTS FOR ELECTRIC HEAT PUMP WATER HEATERS, AND PROPANE USAGE

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October 20, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed January 31, 2019)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ON INCENTIVE LAYERING, THE WILDFIRE AND NATURAL DISASTER RESILIENCY REBUILD PROGRAM, DATA SHARING, RATE ADJUSTMENTS FOR ELECTRIC HEAT PUMP WATER HEATERS, AND PROPANE USAGE

Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE") respectfully submits the following comments on the *Proposed Decision on Incentive Layering, the Wildfire and Natural Disaster Resiliency Rebuild Program, Data Sharing, Rate Adjustments for Electric Heat Pump Water Heaters, and Propane Usage* filed on September 30, 2021 in this proceeding ("Proposed Decision").

MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 to address climate change by reducing energy-related greenhouse gas emissions with renewable energy and energy efficiency at cost-competitive rates while offering economic and workforce benefits, and creating more equitable communities. MCE provides electricity service to more than one million residents and businesses in 36 member communities across Contra Costa, Marin, Napa, and Solano counties with a 1,200 MW peak load.

I. INTRODUCTION

MCE supports the efforts made by the Commission and stakeholders to send a strong signal that building electrification is a key part of California's climate goals. The state has shown leadership in adopting over a dozen decarbonization programs that support building the infrastructure and demand for decarbonization with a variety of administrators, implementers, evaluators and thought leaders. In particular, MCE is supportive of the Commission's adoption of an incentive program for heat pump water heaters through the SGIP program. This kind of leadership is needed to cultivate a broader set of programs and solutions designed to reduce greenhouse gas emissions through fuel switching, load modification, and energy efficiency.

In order to maximize the impact of the decarbonization programs, the Commission should incorporate the following recommendations into the Proposed Decision:

- the TECH project team should develop a common application module for use by Program Administrators ("PAs") and not a statewide online application;
- the incentive layering infrastructure should be available and useful to PAs in addition to evaluators;
- section criteria for the Wildfire and Natural Disaster Resiliency Rebuild ("WNDRR") Program should consider experience working with traumatized populations and empathetic high-touch customer service;
- consider providing resources for local government and community-based organization participation on the WNDRR teams;
- WNDRR evaluation reports should include interviews with program participants; and
- consider how rate impacts may incentivize other behind-the-meter distributed energy resources beyond heat pump water heaters.

II. THE COMMISSION SHOULD DIRECT THE TECH PROJECT TEAM TO DEVELOP A COMMON APPLICATION MODULE FOR PAS AND NOT A STATEWIDE ONLINE APPLICATION

The Proposed Decision is correct in calling for participants to have a seamless experience to maximize program uptake. However, a single statewide online platform to submit and track applications may not accomplish this goal. A statewide application platform may not provide the most efficient and effective experience. Overlapping programs create risk of a sales moment not delivering a participant-friendly experience. PAs are well positioned to integrate programs into a single application and are currently serving at as a single point of contact ("SPOC") for customers.

A. A Statewide Application Platform May Not Provide the Most Efficient and Effective Experience

The Proposed Decision concludes that the TECH Initiative implementer should develop a single online platform where distributors and contractors can submit and track applications for multiple programs at once.[1] A statewide platform to handle all decarb-related project applications may not create an efficient and effective experience. There are likely to be dozens of evolving offerings across all PA types, including investor-owned utilities ("IOUs"), CCAs, RENs, and other non-jurisdictional entities.

MCE is concerned that a statewide platform will require increasingly voluminous and complex information to be maintained at all times which increases the likelihood it will not be kept current or accurate. This introduces concentration risk to the decarbonization program infrastructure in California and should be avoided. The possibility for inaccuracies, potential barriers to keeping the platform current, and potential limitations on incorporating the complexity of decarbonization programs all present risks to the efficient and effective functioning of a statewide application platform. The Commission should avoid these risks at this time. This can be

[1] Proposed Decision, Conclusion of Law 2 at 104.

done by providing an application template and supporting regional efforts for building the groundswell of interest in decarbonization.

B. Creating a Competing Sales Moment for Applicants Will Not Deliver a Participant-Friendly Experience

The Proposed Decision directs implementors and PAs to develop a single, streamlined application for each supply chain level, where possible.[2] MCE supports PAs developing their own integrated applications that incorporate the offerings of other PAs to fill gaps or complement existing offerings. However, if this were done on a statewide platform, there may be overlapping programs of multiple PAs in the same geographic area that serve the same customers with the same technologies or measures for the same purposes within one application.

These programs should be treated agnostically by the statewide platform and thus a sales moment may occur for the overlapping programs if both are available through one application. If competing programs are reaching out to a customer at the same time to attempt to secure participation, it could create significant confusion for and require additional time of the participant. While competing programs should generally compete, this competition is better focused on elements such as marketing, education, and outreach; achieving metrics; or contractor pools. Competition focused at the participant level, especially after an application is submitted, risks creating confusion and undermining a participant-friendly experience.

C. Program Administrators are Well Positioned to Integrate Programs and are Currently Serving as the Single Point of Contact for Customers

MCE and other PAs currently seek to enroll participants in multiple relevant programs whenever possible, and endeavor to do so through an integrated application. Determining which programs actually integrate and how requires complex and, sometimes, iterative work. It may

[2] Proposed Decision at 25.

include redesigning a program to better suit integration or deciding an overlapping program is needed for a portfolio to be cost effective. This work is part of portfolio planning and should remain with the PAs. MCE conducts this work with other CPUC-jurisdictional PAs under a Joint Cooperation Memorandum in the context of energy efficiency programs. MCE also conducts this integrative work through other means with other programs.

MCE works in partnership with PAs like the Bay Area Regional Energy Network ("BayREN") and Silicon Valley Power to provide a heat pump water heater contractor incentive program. MCE also integrates separate programs like the Green and Healthy Homes Initiative with a focus on asthma in Contra Costa County and aging in place in Marin County into energy efficiency programs. PAs are best situated from an informational and decisional perspective to determine which programs actually integrate and how. PAs are undertaking this work now and, as a result, are capable of serving as SPOCs for customers that are navigating multiple programs for a project.

D. The TECH Project Team Should Develop a Common Application Module for PAs to Incorporate Into Their Own Applications

As an alternative to the proposed statewide platform to track integrated applications for all programs, the Commission should direct the TECH project team to develop and maintain a common application module that can be used by PAs to integrate programs into their own applications. This approach is consistent with the Commission's goal of pursuing streamlined, multi-program applications for each supply chain level.[3] This approach supports PAs in maintaining their own integrated applications and simplifies the amount of information that needs to be kept current by the TECH Initiative implementer. It also keeps the complex work of

[3] Proposed Decision at 25.

determining which programs actually integrate and how the details play out in the hands of the PAs, who are well-situated from an informational/decisional perspective to do that work.

This common application module could be developed and maintained by the TECH Initiative implementer. They could maintain a non-exhaustive list of programs generally available throughout the state, including eligibility requirements and application fields. The specific list of programs could be identified by the TECH project team in consultation with the TECH Implementer, PAs, and the CPUC. Keeping this resource up-to-date will help PAs integrate these offerings and expand their reach. The Commission should direct the TECH project team to develop a common application module for PAs to incorporate into their own applications.

III. THE INCENTIVE LAYERING INFRASTRUCTURE SHOULD BE AVAILABLE AND USEFUL TO PAs IN ADDITION TO EVALUATORS

The Proposed Decision directs the TECH Initiative implementer to manage incentive layering infrastructure for the TECH Initiative to coordinate and interact with other building decarbonization incentive programs.[4] This infrastructure should be intended to ensure that layered incentives do not exceed measure cost. MCE supports the development of this infrastructure for use by all PAs in implementing decarbonization programs. This platform could provide a useful tool to check incentives that have been applied at the wholesaler or retailer/contractor level for a project or participant. The platform will also be useful for program evaluation related to incentive caps. MCE strongly encourages the Commission to clarify that the tool will also be available and useful for PAs.

Relatedly, MCE recommends against trying to incorporate all downstream program activity in this platform due to the additional complexity associated with maintaining the

[4] Proposed Decision at 8.

information. Instead, the PAs themselves should manage the incentive caps in the downstream context subject to the oversight of the Commission.

IV. THE STATEWIDE WNDRR PROGRAM SHOULD BE MODIFIED SLIGHTLY TO IMPROVE EFFECTIVENESS AND EVALUATION RESULTS

MCE supports the development of a statewide WNDRR Program and appreciates the Commission's careful consideration in designing the program. MCE agrees with much of the Proposed Decision's features of the WNDRR Program, including county-based implementation teams that incorporate CCAs, local governments, and Community-Based Organizations ("CBOs"). MCE also supports the call for bidders to submit a plan for working with these stakeholders on the county-specific implementation of the WNDRR Program. MCE suggests three modifications of the WNDRR Program below, each intended to enhance the customer experience or evaluation results.

A. The Selection Criteria for the WNDRR Program Should Consider Experience Working with Traumatized Populations and Empathetic High-Touch Customer Service

The WNDRR Program rules articulated in Appendix B of the decision require a request for proposals (RFP) and selection criteria for the Program Implementer.[5] MCE has experience as a wildfire rebuild program partner through the Advanced Energy Rebuild Napa program. Participants in wildfire rebuild programs are much more likely to have experienced significant emotional trauma, which may continue through the long process of rebuilding. As such, the Commission should incorporate an additional criterion for bidders to demonstrate soft skills such as experience working with traumatized populations or with empathetic, high-touch customer service. Selecting implementers using this additional criterion will increase the chance that

[5] Proposed Decision, Appendix B at B-3 to B-5.

customers will be well-served through the difficult process of rebuilding after a wildfire or natural disaster under the WNDRR.

B. The Commission Should Consider Providing Resources to the Local Jurisdiction Member and Community-Based Organization Members of the WNDRR Team

MCE supports the Proposed Decision's inclusion of Local Jurisdiction Members, [6] CBOs[7] and CCAs[8] on the implementation team for a given or potential disaster. These entities are resource limited and likely require supplemental resources to contribute staff time to this effort. The Commission should direct statewide bidders to propose a means by which these members of the WNDRR team can receive funding (e.g. a fixed stipend or reimbursement for hours and expenses) to support their participation on the implementation team. It is only necessary to provide these resources in the context of an emergency or for advanced planning activities. Providing these resources will help ensure continued engagement by each member of the implementation team.

C. The Evaluation Report of the WNDRR Program Should Include Interveiws with Program Participants

The Commission should specify that interviews with participants will be included in the WNDRR Program evaluation report. The Proposed Decision indicates that the evaluation report will address both cost and program effectiveness.[9] MCE supports these elements and encourages the Commission to further specify that interviews with affected homeowners be included in the report. Participants can provide an invaluable perspective on the experience of the program. These perspectives are often actionable insights that help improve program design and should be reflected in the evaluation report requirements.

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[6] Proposed Decision at 43.
[7] *Id.*
[8] Proposed Decision at 45.
[9] Proposed Decision, Appendix B, Section IX.B.5 at B-7.

V. THE COMMISSION SHOULD CONSIDER IMPACTS OF RATE ADJUSTMENTS ON RESOURCES BEYOND HEAT PUMP WATER HEATERS

MCE supports the Commission's decision to direct IOUs to gather information to better understand the bill impacts and guide future rate adjustments for heat pump water heaters. The increased energy usage is a significant factor that should be explored further. Though often, with rate design, making a change to further one objective means impairing the interests of other objectives. While gathering and analyzing the billing information with respect to heat pump water heaters, the Commission should also seek to gain insights to interactive, related, and distinct billing influences and incentives or disincentives to develop other behind-the-meter ("BTM") resources, including energy storage, among the same customers. If any of the customers installing heat pumps have or are developing other BTM technologies at the site, the Commission should seek to gain additional information about those technologies and their relative impact on billing and the heat pump water heater billing impacts. This additional dimension in the data may aid in analyzing how new rates can be balanced to avoid impacting the motivation to install BTM resources, including energy storage.

VI. CONCLUSION

MCE thanks Assigned Commissioner Rechtschaffen, Administrative Law Judge ("ALJ") Tran and ALJ Liang-Uejio for their thoughtful consideration of these comments on the Proposed Decision.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes	))))))	Rulemaking 20-05-003 (Filed May 7, 2020)

OPENING COMMENTS OF PENINSULA CLEAN ENERGY AUTHORITY, CITY AND COUNTY OF SAN FRANCISCO, MARIN CLEAN ENERGY, AND REDWOOD COAST ENERGY AUTHORITY ON THE EMAIL RULING INVITING COMMENTS ON NATURAL GAS ISSUES

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October 21, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes	Rulemaking 20-05-003 (Filed May 7, 2020)

OPENING COMMENTS OF PENINSULA CLEAN ENERGY AUTHORITY, CITY AND COUNTY OF SAN FRANCISCO, MARIN CLEAN ENERGY, AND REDWOOD COAST ENERGY AUTHORITY ON THE EMAIL RULING INVITING COMMENTS ON NATURAL GAS ISSUES

I. INTRODUCTION

Peninsula Clean Energy Authority ("Peninsula"), City and County of San Francisco[1] ("San Francisco"), Marin Clean Energy ("MCE")[2], and Redwood Coast Energy Authority ("RCE") (collectively "Joint CCAs") respectfully submit these comments on the October 13, 2021 *Email Ruling Inviting Comments on Natural Gas Issues* ("Ruling").

The Joint CCAs are concerned by the proposal presented in *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* ("Staff Paper") either to allow or, worse, require Load Serving Entities ("LSEs") to forego building much needed renewable resources in favor of gas expansions. As demonstrated by modeling by the California

[1] CleanPowerSF is the Community Choice Aggregator ("CCA") for the City and County of San Francisco operated by the San Francisco Public Utilities Commission.
[2] MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 to address climate change by reducing energy-related greenhouse gas emissions with renewable energy and energy efficiency at cost-competitive rates while offering economic and workforce benefits, and creating more equitable communities. MCE provides electricity service to more than one million residents and businesses in 36 member communities across Contra Costa, Marin, Napa, and Solano counties with a 1,200 MW peak load.

Energy Commission, such a change would undermine both reliability and California's decarbonization efforts.

II. DISCUSSION

A. The Commission should not allow fossil gas expansions to reduce statewide build of renewable generation and storage.

The Commission should neither allow nor require gas capacity to be used to substitute for the renewable build ordered in Decision ("D.") 21-06-035. Either option would undermine both achievement of California's long term decarbonization goals and grid reliability in the medium term. Energy Commission modeling has demonstrated that swapping renewables for gas reduces reliability. Furthermore, reductions in renewable build requirements will undermine the high pace of renewable procurement needed over the next 25 years to achieve zero or near-zero emissions in 2045. Since state decarbonization targets likely will require retirement of the gas fleet, there is a significant risk gas facilities brought online in the 2020s would become stranded assets. Finally, this proposal would likely result in the Commission increasing its reliance on the efforts of CCAs to meet these objectives.

B. Arguments for allowing fossil gas resources to displace batteries are unfounded and are not grounded in the record.

Despite modeling results indicating that fossil gas resources are unneeded and would undermine reliability, Staff offers speculative concerns, but none are supported by evidence. Furthermore, since the grid needs are for batteries according to both Energy Commission and Staff's modeling, a 24-7 resource is not the correct replacement.

i. Commission concerns that storage will be delayed are speculative and not grounded in the record.

Concerns that supply chain issues may delay battery deployments fail to recognize that the same supply issues would also affect any gas retrofits, so gas projects would not resolve issues of project delays that may be caused by supply chain issues.[3] While impacts from the supply chain are occurring, even if some projects are delayed, the Energy Commission's analysis demonstrates that delaying one-fifth of the projects by a year would not have significant impacts on reliability.[4] Regardless, the supply chain issues that might affect battery projects will also affect gas retrofit projects, especially when retrofits involve installing batteries.

ii. Commission concerns that storage will underperform are speculative and not grounded in the record.

Additionally, Staff's concerns of battery underperformance are similarly speculative. In fact, CAISO presented significant data demonstrating that batteries are performing largely as expected, shifting from ancillary services to provide energy in net peak hours in 2021.[5] The Energy Commission's examination of charging energy shortfalls demonstrates that these issues would have no more than a negligible impact on reliability.[6] Thus, not only does Staff fail to provide evidence of unexpected performance issues, but the record suggests that such unexpected performance issues are not occurring. Additional data should be collected and evaluated, but absent concrete evidence of performance issues, this concern does not constitute a basis for ordering fossil gas procurement.

iii. Commission concerns regarding battery safety ignore similar concerns with gas generation.

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[3] CPUC. Procurement in Compliance with D.19-11-016 per February 1, 2021 Filings. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf.

[4] California Energy Docket 21-ESR-01, Staff Report – Midterm Reliability Analysis, TN# 239881, Table 3. ("Energy Commission Staff Report")

[5] Energy Commission Staff Report, at 15-16, see also, Energy Commission docket 21-ESR-01, Presentation for August 30 Lead Commissioner Workshop on Midterm Reliability Analysis, TN# 239554 (August30, 2021), slide 58-60.

[6] Energy Commission Staff Report, Figures 7 & 8.

The Energy Commission Staff Report suggests that batteries suffer from safety concerns, but neglects to recognize that fossil gas plants suffer from similar issues. The Energy Commission's Staff Report emphasizes a fire at a single 5MW storage facility in Arizona and an overheating event at Moss Landing, but it does not acknowledge the explosion and fire at the Russell City gas plant on May 27, 2021, which took 635MW offline just before the critical 2021 summer season.[7] Similarly, Staff's analysis also fails to note the hundreds of MW of gas capacity that went offline or were subject to thermal derates of gas plants during the heat emergency of August 2020, causing rotating outages.[8] Thus, concerns about battery safety do not constitute a justification to replace these resources with others with similar issues.

C. The Commission should reject any mandate for resources shown to be not needed for reliability

The Commission should reject any proposal for a mandate for fossil gas resources which have been shown to be unneeded for reliability. The Energy Commission's modeling shows that after 2022, there are no system resource needs for additional resources beyond those already ordered, and substituting gas erodes reliability. The Energy Commission's modeling is abundantly clear that after 2022, there are no system resource needs for additional resources beyond those already ordered, and substituting gas erodes reliability.[9] All of the scenarios modeled, except for those substituting fossil gas generation for renewable procurement, have Loss of Load Expectations ("LOLE") far below 0.1, demonstrating there is no need for additional resources for reliability. In addition, Energy Commission's modeling demonstrates

[7] https://www.hayward-ca.gov/your-government/departments/city-managers-office/russell-city-energy-center

[8] California Independent System Operator, California Public Utilities Commission, & California Energy Commission, Final Root Cause Analysis, January 2021, at 47.

[9] Energy Commission docket 21-ESR-01, Presentation for August 30 Lead Commissioner Workshop on Midterm Reliability Analysis, TN# 239554 (August30, 2021), slides 32-33

that substituting renewables with gas increases LOLE from extremely low levels (below 1 in 2,000) to nearly a 0.05 LOLE in 2026 (0.042). This study demonstrates allowing gas to be substituted degrades reliability.

D. The Commission should reject any technology-specific mandate for fossil gas.

The Commission should continue its existing approach and firmly reject the proposal for any technology specific mandate for fossil gas resources, especially when alternatives have not even been considered, much less analyzed. Even if there were credible arguments for some firm resource as a hedge against unforeseen events, Staff has made no attempt to demonstrate that fossil gas generation is uniquely suited to this role, especially when clean firm resources that would not undermine decarbonization efforts, have been shown to improve reliability compared to portfolios containing additional amounts of fossil gas resources.[10] If the Commission were to consider a firm resource mandate, LSEs should be free to procure clean firm resources, which would perform similar functions while improving GHG reduction performance.

III. REQUESTED FEEDBACK ON SPECIFIC ISSUES POSED IN THE RULING

1. The assumptions and conclusions of the RESOLVE analysis that includes gas capacity upgrades as a candidate resource.

A. The analysis of greenhouse gas emissions is too imprecise to conclude this proposal would not increase greenhouse gas emissions.

Estimates of the emissions impacts in the Staff Report are too imprecise to conclude that this proposal would not increase emissions each year through 2045, because RESOLVE does not have the granularity to draw conclusions about the emissions impacts of upgrading CAISO's gas fleet. Precise estimates are important, because evaluating the full cost of the proposal depends on the levels of emissions. Claims that the proposal would not result in increased emissions after

[10] Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning, October 2021, ("Staff Paper"), at 4.

2030 has not been independently corroborated in a more granular Production Cost Model. RESOLVE is a capacity expansion tool that cannot be relied upon for estimating emissions, especially when compared to more granular Production Cost Models such as SERVM, which historically has differed from the RESOLVE model by a wide margin (for example showing that RESOLVE estimates of 37.6 MMT in 2020 significantly underestimated CAISO system emissions, which were closer to 49.3 MMT.)[11] The fact that RESOLVE reports emissions consistent with the limits imposed in the model does not provide a reliable estimate of how the selected portfolio would actually perform when dispatched in CAISO markets, which do not impose an aggregate GHG limit on dispatch. When comparing emissions results between RESOLVE and the real world, RESOLVE underestimates real world emissions by many millions of metric tons.[12] Staff recognizes the need to develop more robust analyses on the impact of the gas upgrade proposal on emissions.[13] Until there are firm analyses demonstrating this proposal would not increase emissions, the Commission should not move forward.

B. The analysis fails to evaluate other firm technologies that could address concerns without undermining reliability and greenhouse gas targets.

Deploying gas resources to address resource diversity concerns would not be appropriate until alternative clean resources have also been evaluated. If clean resources are able to meet the same needs as fossil gas resources would, without increasing emissions, these should be preferred. These and other technologies are likely to be critical in full decarbonization of the grid and so represent much longer-term investments than gas retrofits which would only be useful for a limited time.[14] Such resources would provide superior GHG performance, and may

[11] See, *e.g.*, IRP Model Improvement and GHG Ground Truthing Webinar, December 9, 2020, at 30.
[12] *Id.*
[13] Staff Paper, p. 16.
[14] Long, J, Baik, E., Jenkins, J, Kolster, C., Chawla, K. Olson, A, Cohen, A, Colvin, M, Benson, S., Jackson, R., Victor, D, & Hamburg, S., *California needs clean firm power and so does the rest of the*

also provide for lower annual capacity costs, since clean resources would be able to operate past 2045, unlike fossil gas resources, allowing longer amortization periods and a greatly reduced risk of stranded assets. The Commission should analyze alternatives before making a decision regarding the best approach to mitigate important concerns of grid reliability and pollution.

C. The cost-effectiveness calculations in the Staff Report do not adequately focus on the most likely fossil gas generation financing scenarios.

Any cost-effectiveness analysis should be based on real-world cost estimates, reflect the reality of the necessary schedule of decarbonization to avoid stranding these assets in the future, and reflect the realities of contracting gas resources.

The Commission should only consider the high-cost estimates and short amortization periods to capture the downside risks. The "low" cost estimates are unlikely to be realistic because these are below the current value of Resource Adequacy, which are approximately \$5.20/kW-month, or \$62.40/kW-year (as measured by RA-only market transactions).[15] Since the value of the Resource Adequacy alone falls between the high and very high values, the Joint CCAs question whether the "low" or "high" values are realistic. If costs were this low, generators would likely already be planning upgrades to capture this value, yet the large volume of permitted but unbuilt projects cited in the analysis suggests that upgrade projects are not economical.

In addition, the 25-year amortization period apparently used in the RESOLVE model may also be unrealistic. It is unclear that retrofit projects can obtain such long-term contracts. For example, contracts for CCGT2 resources from Southern California Edison's ("SCE's")

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world: Three detailed models of the future of California's power system all show that California needs carbon-free electricity sources that don't depend on the weather. (2021) Issues in Science and Technology, available at: https://www.edf.org/sites/default/files/documents/LongCA.pdf.

[15] *Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up,* issued November 2, 2020 by ED staff pursuant to D. 19-10-001, Table 1.

public 38 MMT IRP filing suggest typical terms are closer to 5 to 7 years.[16] Furthermore, decarbonization requirements may force retirements by the mid 2040s implying an amortization period considerably less than 25 years.[17] Most critically, the scientific reality is that limiting temperature increases to below 2ºC requires full decarbonization by 2045, according to the IPCC.[18]

Combining the most likely capacity costs and shorter amortization periods results in a range of costs closest to the "very high" cost values. Thus, of the results of the Staff study, the Commission should make decisions solely based on the "very high" values as the most conservative and most reasonable estimates which raises significant risks of imposing unreasonable costs on ratepayers. System benefits are unlikely to exceed the $15 to 50 million in savings cited for the "very high" cost scenario.[19] These savings are so modest that even small errors in calculation could completely eliminate any actual savings, especially when considering the costs to the public of the impacts of the emissions.

These savings are dwarfed by the increase of hundreds of millions of dollars spent by the IOUs increasing their wildfire prevention efforts to address the impacts of decades of carbon emissions.[20]

D. The cost effectiveness calculations presented in the Staff Report should incorporate the full social and mortality costs of fossil gas generation.

[16] Appendix E.1 Resource Data Template – SCE 38 MMT Preferred Conforming Portfolio [PUBLIC], available at https://www.sce.com/regulatory/CPUC-Open-Proceedings (R.20-05-003).
[17] Executive Order B-55-18, available at https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf (ordering the California Air Resources Board to plan for full decarbonization by 2045)
[18] Intergovernmental Panel on Climate Change (2018) Global Warming of 1.5C Report, Chapter 2, at 95, https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_Chapter2_Low_Res.pdf.
[19] Staff Paper, at 12.
[20] California Public Utilities Commission, Utility Costs and Affordability of the Grid of the Future: An evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1, at 34-35.

Most critically, cost effectiveness evaluation of fossil fuel resources should consider the full costs to ratepayers. While some ratepayer costs are charged on electricity bills, externalities, like wildfire costs, drought impacts and heatwave costs, are also paid by ratepayers. The Commission has previously recognized that these costs need to be incorporated in portfolio planning in the Integrated Resources Planning proceeding in D.19-05-019. The Decision emphasized the importance of using the high impact values because of "extensive evidence that the [federal] Interagency Working Group's average values underestimate the damage costs associated with climate change, [because] a list of damages [are] excluded from the Interagency Working Group's estimates: damages from wildfires, costs of climate change associated with electricity infrastructure including effects of extreme heat, and impacts of flooding." It is time the Commission begins incorporating the costs values established in that decision.[21] Incorporating these values would comply with the direction of the legislature that "in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity…"[22]. Public Utilities Code 701.1 makes clear that, "in calculating the cost-effectiveness of energy resources, including conservation and load management options, the commission shall include, in addition to other ratepayer protection objectives, a value for any costs and benefits to the environment, including air quality." [23]

If the Commission were to apply the cost values identified in D.19-05-019, the potential savings reported in the Staff Paper are all but eliminated by the social costs of the carbon emissions. If the real-world emissions as estimated by RESOLVE are even fractionally too low,

[21] D.19-05-019, at 40-42, Ordering Paragraphs 5 through 7.
[22] Public Utilities Code § 701.1(a).
[23] Public Utilities Code § 701.1(c).

there are no ratepayer savings from this proposal. For example, applying the "High Impact" value from D.19-05-019 to the "very high" cost scenario suggests that these costs would reduce the cost savings by approximately $14 million, which is already greater than the low end of the cost savings range reported by staff.[24] If the RESOLVE estimates are as little as 0.25 MMT below real-world emissions that would result, any cost savings are completely eliminated. Given the strong likelihood that RESOLVE underestimates real-world emissions as described above, the Commission should not conclude this proposal would result in real world cost savings.

Recent advances in climate science have also provided quantitative estimates of a portion of the excess deaths attributable to carbon emissions, and the Commission should consider these excess deaths when making decisions. Scientifically, carbon emissions contribute to increased temperatures going forward and such increases will increase the frequency and severity especially of lethal heat waves.[25] Recent scientific work has estimated that every ton of carbon emissions will result in excess deaths from these increased heatwaves through 2100 on the order of 2.26×10^{-4} excess death[26] per ton of carbon emitted.[27] Since these estimates were not available when the Social Costs of Carbon were calculated in D.19-05-019 or the cost estimate discussed therein, these mortality costs should be reflected in estimates of the externality costs borne by the public. The Joint CCAs highlight the importance of this issue because many of these impacts are

[24] D.19-05-019 "High impact values in 2025 are $138/ton. D.19-05-019, at Table 2. Staff Paper Figure 9 shows 2026 emissions increases of approximately 100,000 tons in 2026, suggesting the social costs are on the order of $13.8 million, although there is a high statistical error around this estimate.
[25] IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [MassonDelmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)], Cambridge University Press. In Press. at finding A.3.
[26] These estimates do not include the deaths attributable to fires, floods, droughts or famine.
[27] D.L. Besler (2021) The mortality cost of carbon, Nature Communications 12:446, https://doi.org/10.1038/s41467-021-24487-w.

likely to occur among vulnerable populations across the Global South.[28] The Commission should be cautious about pursuing limited cost savings without considering such an important impact, which would increase the human cost of our energy sector.

By way of illustration of one approach the Commission could take to incorporating these considerations, many regulatory agencies apply a statistical value of a life when evaluating the cost impacts of mortality of regulated activities. While these methodologies are highly complex, and beyond the scope of the current analysis, the Commission should examine the approaches taken by its partner public regulators. For example, the federal Environmental Protection Agency ("EPA") reports a range of the value of statistical lives in the academic literature using a range of methods from \$0.85 million per life saved to nearly \$20 million.[29] The EPA itself uses approximately \$7.4 million per life. For illustration, estimates using EPA's value would be that the carbon emissions estimated by RESOLVE would impose additional costs of \$418 million a year from causing more than 50 deaths a year under this proposal. While these estimates are merely indicators and development of robust mortality cost estimates would require considerable careful work, the rough magnitude of these social and mortality costs suggest the Commission should be extremely cautious in considering emissions impacts. If RESOLVE underestimates real-world emissions and the social and human costs are not reflected, additional gas

[28] Doblas-Reyes, F.J., A.A. Sörensson, M. Almazroui, A. Dosio, W.J. Gutowski, R. Haarsma, R. Hamdi, B. Hewitson, W.-T. Kwon, B.L. Lamptey, D. Maraun, T.S. Stephenson, I. Takayabu, L. Terray, A. Turner, and Z. Zuo, 2021: Linking Global to Regional Climate Change. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [MassonDelmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. In Press., available at https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter_10.pdf.

[29] Environmental Protection Agency, Guidelines for Preparing Economic Analyses, (December 2010, updated May 2014), Appendix B, Table B.1.

procurement may deliver illusory savings while imposing public costs that would make ratepayers and society worse off.

2. Whether gas capacity upgrades at existing sites should be considered as eligible resources for the procurement requirements of D.21-06-035? If so, which of the various procurement process steps of D.21-06-035 would need to be amended, and how?

The Commission should neither allow nor require gas capacity to be used to substitute for the renewable build ordered in D.21-06-035. Either option would undermine both achievement of California's long term decarbonization goals and grid reliability in the medium term.

First, allowing LSEs to reduce their renewable resource procurement would undermine deep decarbonization goals. Achieving near zero emissions in 2045 will require significant renewable and storage build every single year through 2045, as indicated by both SB100 modeling and modeling in this docket. The procurement in D.21-06-035 is broadly compatible with the trajectories of buildout modeled in SB100 (e.g. 1.7 to 2.7 GW of solar, 0.9 GW of wind, and between 1.7 and 2.2 GW of storage each year from 2021 through 2045).[30] Substituting gas for renewable build will necessarily reduce the required renewable build from 2021 through 2026. Reducing the procurement of storage and other renewables for the years 2023 through 2026 could jeopardize the trajectories required to achieve deep decarbonization by 2045.

Furthermore, Staff's analysis fails to consider the significant risk that once investments are made in upgrading fossil gas resources, it may prove difficult to force retirement of such resources to fully decarbonize the grid as accelerating climate change makes it increasingly imperative to achieve carbon neutrality in accordance with Executive Order B-55-018. By promoting such investments today, the Commission may be prejudicing future alternatives to full

[30] Energy Commission docket 19-SB-100, Presentation – SB100 Draft results, TN# 234549.

decarbonization. The CEC study indicates clean firm resources can likely serve similar functions without this risk to decarbonization.[31]

Finally, allowing LSEs to swap gas for renewables may allow some LSEs to lean on the renewable energy procurement of others to keep the state on target for total renewable build needed to hit 2045 targets. As noted in the August 17 *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* the aggregated IRPs came in under system-wide GHG targets because several LSEs, namely CCAs, planned to more aggressive decarbonization and greater renewable procurement, while planned new build was substantially lower for ESPs and IOUs. As a result, the state is relying heavily on CCAs to build the renewables each year for California to stay on a trajectory to meet the state's 2045 goals. Allowing other LSEs to swap gas for renewables will only increase the Commission's already heavy reliance on CCA efforts to ensure enough renewables are built to stay on target for 2045 goals. CCAs set their goals in order to exceed state requirements and accelerate the transition to clear energy. The Commission should avoid allowing other LSEs to lean on CCA policies to meet state GHG goals. Doing so undermines the accelerating impact of those policies as it uses the excess accomplishment to achieve a required standard.

3. *Whether load serving entities that wish to contract with gas capacity upgrades at existing sites, if permitted by the Commission, should be required to demonstrate that they first attempted to procure non-emitting resources. If so, what should this demonstration consist of, and on what timeframe?*

See response to Question #2 and Question #4. Load Serving Entities seeking to use gas to meet the obligations of D.21-06-035 should demonstrate at minimum that they actively sought to procure non-emitting resources and also that the project would not result in a net increase in

[31] Energy Commission Staff Report, at 7 *et seq*.

GHG emissions and would result in a net decrease in local criteria pollutant emissions in disadvantaged communities or non-attainment areas.

4. If the Commission allows gas capacity upgrades at existing sites, whether the Commission should restrict or prohibit gas capacity upgrades in disadvantaged communities, as defined by the CalEnviroScreen tool, or impose some other/additional criteria.

Staff's analysis neglects to assess whether there are significant environmental impacts to air quality that may need to be mitigated. The Commission should not allow LSEs to procure resources that are likely to increase local criteria pollutant emissions in disadvantaged communities. The Staff Paper lists "air quality" as an "area for further analysis" and acknowledges that "while some plant efficiency improvements may decrease the rate of criteria pollutant emissions, it is possible that increased plant dispatch could lead to overall greater emissions." [32] However, the failure to provide even a cursory attempt at analyzing the potential impacts of the gas upgrade and expansion proposal on local air quality across the state and in disadvantaged communities is troublesome. The Commission must ensure that load-serving entities' procurement "minimize[s] localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities."[33] Allowing LSEs to procure gas to meet their D.21-06-035 obligations is contrary to statute because it will likely not contribute to a minimization of local criteria air pollutants. Furthermore, adopting a policy that could compromise air quality for a reliability need that has already been addressed through the existing order for non-gas procurement (D.21-06-035) and for which it has been found that relying on non-emitting resources does not diminish reliability compared to portfolios that contain gas resources, is unwarranted.[34]

[32] Staff Paper, p. 16.
[33] Public Utilities Code section 454.52(a)(1)(I). See also, Public Utilities Code § 701.1(c).
[34] Staff Paper, p. 4.

The Joint CCAs recommend that the Commission examine the local criteria pollutant impacts of each of the upgrade potential capacity amount scenarios before making a determination as to whether it should allow gas capacity upgrades to be considered eligible resources for procurement to meet D.21-06-035. Then, based on those results, if the Commission decides to allow gas capacity upgrades at existing sites, it should require LSEs conducting the gas upgrades to demonstrate that the upgrade will result in a net decrease in local criteria pollutant emissions. In particular, any upgrades to a gas plant under this proposal should be required to demonstrate it would decrease emissions of particulate matter (PM2.5 and PM10), nitrogen oxides (NO_x), and sulfur oxides (SO_x), with decreases in any disadvantaged communities, non-attainment areas, or near sensitive receptors as the first priority.

IV. CONCLUSION

The Joint CCAs are concerned that the analysis used as the basis of the proposal in the Staff Paper is not robust and has significant omissions, which may lead to poor policy choices, while it ignores the conclusions of the California Energy Commission that substituting gas for renewables is not needed for reliability and would be detrimental for reliability. The proposed fossil gas upgrades may undermine efforts to fully decarbonize the grid in the future. For these reasons, the Joint CCAs respectfully request that the Commission adopt the recommendations made herein. The Joint CCAs look forward to working with the Commission to address California's energy needs.

October 21, 2021

Respectfully submitted,

/s/*Doug Karpa*

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October 22, 2021

Jerry Huerta
Senior Counsel, Law
Gas & Electric Operations
Pacific Gas and Electric Company
Sent via email

Re: Marin Clean Energy's Participation in PG&E's Percentage of Income Payment Plan Pilot

Dear Mr. Huerta:

Pursuant to Decision 21-10-012, Ordering Paragraph 3, Marin Clean Energy ("MCE") hereby provides notification of its intent to participate in the Percentage of Income Payment Plan ("PIPP") Pilot.

If you have any questions, please contact me at (415) 464-6040 or sswaroop@mcecleanenergy.org.

Sincerely,

Shalini Swaroop
General Counsel and Director of Policy

Cc: Megan Lawson
Stacey Richardson
Service List for R.18-07-005

CONCORD OFFICE: 2300 Clayton Road, Suite 1150, Concord, CA 94520
SAN RAFAEL OFFICE: 1125 Tamalpais Avenue, San Rafael, CA 94901
mceCleanEnergy.org

Submit comment on Phase 2 Straw Proposal

Initiative: Resource adequacy enhancements

1. Provide a summary of your organization's comments on the phase 2 straw proposal:

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Resource Adequacy (RA) Enhancements Phase 2 Straw Proposal. In summary:

- CalCCA supports the California Independent System Operator's (CAISO's) clarification for eligible intermittent resources;
- The CAISO should work with stakeholders to address Investment Tax Credit (ITC) considerations prior to adopting a must offer obligation for the charge portion of storage resources;
- CalCCA recommends the CAISO maintain the real-time must offer obligation and zero-dollar imbalance reserve bidding requirement for RA resources; and
- CalCCA supports the CAISO's proposal to modify the flexible resource adequacy program in three stages and offers a recommendation regarding exemptions to the economic bidding requirement.

2. Provide your organization's feedback on the Must Offer Obligations and Bid Insertion topic as described in section 4.1:

Clarifications to the Eligible Intermittent Resource Must Offer Obligation

CalCCA supports the CAISO's clarification for eligible intermittent resources that any energy above the resources' net qualifying capacity (NQC) cannot be used to support an export from non-RA capacity and that the RA capacity under offer obligation to the CAISO is for all energy necessary to derive the shown RA value. This is appropriate for resources with an NQC value established through an effective load carrying capability methodology.

ITC Considerations

CalCCA is concerned with the CAISO's proposal that storage resources must bid their full charge and discharge capability to fulfill their must offer obligation. The CAISO indicates its expectation that resources manage ITC grid charging restrictions through bidding. However, resources cannot fully capture the costs of losing ITC credits in their bids in all instances. When the next megawatts (MW) of grid charging results in the resource losing their ITC credit, a $1000 bid may not be sufficient to reflect the cost of the lost ITC credit. The CAISO must provide resources a mechanism to maintain their ITC credit because contracts have already been executed by load-serving entities (LSEs) to procure ITC-eligible resources prior to the development of RA rules for those resources.

The CAISO indicated on the stakeholder call that it would further consider how to accommodate ITC requirements in the Energy Storage Enhancements initiative. The CAISO should allow solutions to develop in that stakeholder process prior to modifying the storage must offer obligation to require bidding of the full charge and discharge capability.

Crossover with Day-Ahead Market Enhancements (DAME) Initiative
The CAISO proposes a standard 24 by 7 must offer obligation in day-ahead and real-time through the DAME transitionary period. As stated in CalCCA's comments to the DAME second revised straw proposal, CalCCA does not support the CAISO's proposal to relieve RA resources of their real-time must offer obligation after the day-ahead market if they do not receive a day-ahead award once the DAME transitionary period ends.[1] Instead, CalCCA recommends the CAISO maintain the real-time must offer obligation for RA resources. The CAISO should also require RA resources bid zero dollars and not receive the marginal price for imbalance reserves until the impacts of removing the zero-dollar bidding requirement can be evaluated within the Extended Day-Ahead Market (EDAM) initiative.

As outlined in CalCCA's DAME comments, because RA resources are already paid to be available to provide energy through real-time, the CAISO should not release that capacity already paid for after the day-ahead market. The CAISO proposes the transition period in part to allow time for RA contracts to be updated to account for the removal of the RA real-time must offer obligation and zero-dollar imbalance reserve bidding requirement. However, the ability for LSEs to renegotiate RA contracts already executed to account for this change will be extremely difficult given tight supply conditions in the RA market. The result of implementing this change under current RA market conditions could result in LSEs paying for resources to be available to provide energy twice; first, within the RA market when procuring RA capacity, and second, within the day-ahead market when procuring imbalance reserves and reliability capacity. As such, CalCCA has significant concerns around the feasibility of renegotiating RA contracts at a reasonable price to facilitate this structural change without significant increases in ratepayer costs.

Additionally, if RA resources are relieved of their must offer obligation after the day-ahead, the CAISO market would not receive the full benefit of having all resources and their attributes that have already been paid for available to meet grid needs. Relieving RA resources of their real-time must offer obligation after day ahead could result in the

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[1] CalCCA Comments to the Day-Ahead Market Enhancements Second Revised Straw Proposal: https://stakeholdercenter.caiso.com/Comments/AllComments/0860b0d0-5bc0-48f4-af5e-b63b28fb71b0#org-7da099a9-4c56-4d71-9fb9-2fe8f7c6da05.

CAISO needing to rely on out-of-market actions to access the resource in the event conditions in real-time require additional resources beyond what is procured through the imbalance reserve or reliability capacity products to maintain grid reliability. Given the costs of making resources available through real-time are already covered in RA contracts, the CAISO should not limit its access to resources already procured to maintain grid reliability, and instead, should maintain the real-time must offer obligation for RA resources within this initiative.

Finally, CalCCA supports the CAISO requirement for RA resources to bid zero dollars for imbalance reserves and recommends RA resources be required to bid zero dollars and not receive the marginal price for imbalance reserves until the impacts of removing the zero-dollar bidding requirement can be evaluated within the EDAM initiative. This is consistent with the current RUC process. CalCCA understands the rationale behind removing the zero-dollar bidding requirement under an EDAM where resources in other balancing authority areas would be bidding for the same products without the zero-dollar bidding requirement. However, given the difficulty LSEs will face renegotiating contracts under current RA market conditions, the CAISO should not consider removing the zero-dollar bidding requirement within the DAME initiative. Additionally, the CAISO should not pay RA resources the marginal price for imbalance reserves and reliability capacity since existing RA contracts already compensate resources for being available through real-time. Instead, the CAISO should maintain the zero-dollar bidding requirements and continue not to pay resources for capacity already accounted for in RA contracts indefinitely until this change can be fully evaluated within the EDAM initiative.

3. Provide your organization’s feedback on the Flexible RA topic as described in section 4.2:

Staged Approach to Modify the Flexible RA Program

CalCCA supports the CAISO’s proposal to modify the flexible resource adequacy program in three stages, in which:

- Stage 1 would maintain the existing flexible RA program and require all resources eligible of providing imbalance reserves to submit economic bids in the day-ahead market and bid zero dollars for imbalance reserves;
- Stage 2 would evaluate whether a separate flexible RA requirement is necessary; and
- Stage 3 would implement new flexible RA program or sunset the existing flexible RA program.

This approach will allow the CAISO to examine whether a separate flexible RA requirement is needed after the modifications to self-schedule rules proposed in this initiative and the imbalance reserve product proposed in DAME are in place. Additionally, broader RA structural changes are being examined in the California Public Utilities Commission’s RA reform track. The outcome of that effort may further reduce the need for a separate flexible RA program and should be considered in the CAISO's evaluation in Phase 2.

Further, CalCCA agrees with the CAISO that LSEs will procure with the CAISO's predictable net-load ramps in mind, considering trade-offs among cost, ramp rate, and renewable portfolio obligations and targets.[2] Therefore, CalCCA supports a staged approach that includes an evaluation of whether a separate flexible RA requirement is needed. If the CAISO finds that the system and local RA programs adequately address the CAISO's operational needs following the proposed changes, it would be prudent for the CAISO to eliminate the flexible RA requirements, as it would significantly reduce the complexity of the RA program.

Exemptions to the Economic Bidding Requirement

As described in the must offer obligation comments above, storage resources must have a mechanism to allow them to schedule in such a way that they can meet both the must offer obligation and generate energy that allows them to charge the storage component with the Variable Energy Resource (VER) component when it is economical to do so. The CAISO should not penalize hybrid or co-located resources for self-scheduling storage charging in day-ahead with VER production to displace grid charging.

4. Please provide your organization's feedback on the proposed EIM Governing Body role as described in section 5:

No comments at this time.

5. Please provide your organization's feedback on the Appendix as described in section 7:

No comments at this time.

6. Additional comments on the Resource Adequacy Enhancements phase 2 straw proposal:

The CAISO intends to take Phase 2 elements to the Board of Governors in February 2022. Given the interdependencies between these proposals and the DAME initiative, the CAISO should ensure the timing of board approval is aligned for both initiatives, to ensure proposals in this initiative align with the final DAME design.

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2 Resource Adequacy Enhancements Phase 2 Straw Proposal at 18.

ATTACHMENT A

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT OF MARIN CLEAN ENERGY FOR PERIOD JULY 1 – SEPTEMBER 30, 2021

Pursuant to Decision 18-06-027 ("Decision")[1] and in accordance with Resolution E-4999,[2] Marin Clean Energy ("MCE") files this quarterly report on the Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CS-GT") programs for the period July 1 - September 30, 2021. MCE reports on the following program metrics as required by Resolution E-4999:

1. Capacity procured and online;
2. Participating customers, including breakdown by Disadvantaged Community ("DAC");
3. California Alternate Rates for Energy ("CARE") and Family Electric Rate Assistance ("FERA") enrollment.[3]

1. Capacity Procured and Online

The DAC-GT program (branded as MCE's "Green Access" program) has a capacity cap of 4.64 MW. The CS-GT program (branded as MCE's "Community Solar Connection" program) has a capacity cap of 1.28 MW.[4]

On August 27, 2021, MCE launched the first DAC-GT and CS-GT solicitation with bids due on November 19, 2021. As of the filing of this report, MCE has not entered into any long-term offtake agreements to procure capacity for the DAC-GT or CS-GT programs. Hence, MCE does not have any capacity procured or online under either the DAC-GT or the CS-GT program.

Enrolled customers under the DAC-GT program are currently being served by "interim resources" that meet the eligibility requirements of the programs in accordance with Resolution E-4999.[5] MCE is serving DAC-GT customer with solar generation from the Goose Lake project, located at 15004 Corcoran Rd., Lost Hills, CA 93249 in DAC census tract 6031001300.

2. Participating Customers

The DAC-GT and CS-GT programs provide a 20% bill discount to eligible customers located in DACs. DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen ("CES") tool as among the top 25 percent of census tracts statewide, plus the

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[1] D.18-06-027 authorized Community Choice Aggregators (CCAs) to offer DAC-GT and CS-GT programs to their customers. See D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, OP 17 at p.104.

[2] Resolution E-4999, *Approving with Modifications Tariffs to Implement the Disadvantaged Communities Green tariff and Community Solar Green Tariff Programs*, OP 1(f) at p.63.

[3] Id.

[4] Resolution E-4999 allocated 4.31 MW of capacity to MCE for the DAC-GT program and 1.11 MW for the CS-GT program. See Resolution E-4999 at p.14. MCE assumed additional program capacity from non-participating CCAs in MCE AL 42-E-B, leading to a total program capacity of 4.64 MW for the DAC-GT and 1.28 MW for the CS-GT program.

[5] Resolution E-4999 at p.24.

census tracts in the highest five percent of CES' Pollution Burden that do not have an overall CES score because of unreliable socioeconomic or health data.[6]

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[7] In MCE AL 42-E-A, MCE opted to auto-enroll eligible customers that live in one of the top 10% of DAC census tracts statewide in MCE's service area if they meet certain criteria.[8]

The CS-GT program is available to residential customers who live in DACs (as defined by D.18-06-027) and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor. A solar generation project supporting the program must be located within five miles of the participating customers' census tract. At least fifty percent of a project's capacity must be reserved for low-income customers, defined as those meeting the income qualifications for either the CARE or FERA programs.

Table 1 describes, for each program, the participating customers to date. As noted above, MCE is still in the process of procuring solar generation for the CS-GT program and has hence no participating customers under the program. Participating customers under the DAC-GT program are being served by interim resources.

Table 1: Participating Customers in DAC-GT and CS-GT Programs

	DAC-GT	**CS-GT**
Customers Subscribed as of 09/30/2021	3,157	0

Table 2 indicates the number of customers participating in the DAC-GT program grouped by DAC census tract number.

[6] See Conclusions of Law #3 in D.18-06-027 at p.96.

[7] Customers must be eligible to participate in either the CARE or FERA programs; they are not required to be enrolled under those programs to be eligible to participate in DAC-GT. CARE/FERA eligibility is established as currently defined under those programs.

[8] See more details in MCE AL 42-E-A at p.4.

Table 2: DAC-GT Participants by DAC Census Tract

Census Tract	County	City (closest by proximity)	Count
0133770005	Contra Costa	Richmond	412
0133120001	Contra Costa	Pittsburg	356
0133770004	Contra Costa	Richmond	310
0133790004	Contra Costa	Richmond	290
0133650021	Contra Costa	Richmond	267
0133650023	Contra Costa	Richmond	255
0133790001	Contra Costa	Richmond	213
0133650022	Contra Costa	Richmond	207
0133790003	Contra Costa	Richmond	195
0133770003	Contra Costa	Richmond	192
0133790002	Contra Costa	Richmond	168
0133770001	Contra Costa	Richmond	159
0133770002	Contra Costa	Richmond	133

3. CARE/ FERA Enrollment

To date, no CARE/ FERA enrollment occurred as a result of the DAC-GT or CS-GT enrollment for customers in MCE's service area.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 Filed July 10, 2014
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT OF MARIN CLEAN ENERGY FOR PERIOD JULY 1 – SEPTEMBER 30, 2021

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October 29, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 Filed July 10, 2014
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QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT OF MARIN CLEAN ENERGY FOR PERIOD JULY 1 – SEPTEMBER 30, 2021

Marin Clean Energy ("MCE") submits this Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CS-GT") quarterly report in accordance with Resolution E-4999. Ordering Paragraph ("OP") 1(f) of Resolution E-4999 states:

> "Once an IOU has completed its first RFO or initiated customer enrollment, whichever occurs first, within 30 Calendar Days after the end of each calendar quarter, PG&E, SCE, and SDG&E shall file a report in R.14-07-002, or a successor proceeding, and serve the same report on that service list, for the previous quarter and cumulatively, with the following minimum information for the DAC-GT and CSGT programs: capacity procured, capacity online, and customers subscribed. The quarterly reports should also identify the DACs in which DAC-GT or CSGT project is located and list the number of customers participating in each program in each DAC within a utility's service territory. Finally, the quarterly reports must include the number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CSGT programs."[1]

[1] Resolution E-4999, *Approving with Modifications Tariffs to Implement the Disadvantaged Communities Green tariff and Community Solar Green Tariff Programs*, OP 1(f) at p.63.

D.18-06-027 authorized Community Choice Aggregators ("CCAs") to offer DAC-GT and CS-GT programs to their customers.[2] As program administrators, CCAs are subject to the same reporting requirements as investor-owned utilities ("IOUs"). Hence, MCE hereby submits a quarterly report covering the period of July 1 to September 30, 2021, attached hereto as Attachment A.

Respectfully submitted,

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Dated: October 29, 2021

[2] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, OP 17 at p.104.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON EMAIL RULING INVITING COMMENTS ON NATURAL GAS ISSUES

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October 28, 2021

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should not mandate the procurement of natural gas capacity;
- The cost and market value assumptions utilized in Commission Staff's Renewable Energy Solutions Model (RESOLVE) analysis are unexplained and have not been justified; and
- The Net Qualifying Capacity (NQC) of resources analyzed in Commission Staff's RESOLVE analysis must be reconciled with more recent assessments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON EMAIL RULING INVITING COMMENTS ON NATURAL GAS ISSUES

The California Community Choice Association[1] (CalCCA) submits these Reply Comments in response to the Email Ruling Inviting Comments on Natural Gas Issues (Ruling), issued October 13, 2021. The Ruling requests comments on the California Energy Commission's (CEC's) *Staff Report, Mid-Term Reliability Analysis*,[2] the Commission's staff paper entitled *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning*,[3] and questions set forth in the Ruling.

I. INTRODUCTION

Parties faced a variety of challenges in responding to the Ruling, including an extremely compressed comment timeline and an abbreviated analysis performed outside of the normal Integrated Resource Planning (IRP) modeling process, using unexplained and unjustified assumptions.[4] CalCCA appreciates the comments provided by parties and offers the following conclusions:

- The Commission should not mandate the procurement of natural gas capacity;

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *California Energy Commission Staff Report, Midterm Reliability Analysis,* Docket No. 21-ESR-01, CEC-200-2021-009 (Sept. 30, 2021) (CEC Staff Report).

3 *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning, CPUC Staff Paper* (Oct. 2021) (CPUC Staff Paper).

4 CalCCA did not file Opening Comments due to these challenges.

- The cost and market value assumptions utilized in Commission Staff's RESOLVE analysis are unexplained and have not been justified; and
- The NQC of resources analyzed in Commission Staff's RESOLVE analysis must be reconciled with more recent assessments.

II. REPLY TO VARIOUS PARTY COMMENTS

A. The Commission Should Not Mandate the Procurement of Natural Gas Capacity

The Commission should not mandate that load-serving entities (LSEs), including community choice aggregator (CCAs), procure natural gas resources as part of the procurement order for the Mid-Term Reliability (MTR) Decision[5] or any other procurement order. With respect to CCAs, Public Utilities Code section 366.2(a)(5) allows CCA governing authorities to fulfill procurement requirements in a way that best addresses the needs and preferences of their communities.[6] In addition and as discussed below, the analysis underlying the conclusion that natural gas resources are needed is flawed by unexplained and unjustified inputs.

Parties argue that mandating the procurement of natural gas resources: (1) is unnecessary for reliability as set forth in the CEC's MTR analysis; (2) could undermine long-term decarbonization goals and grid reliability; and (3) could result in the assigning of market power to one resource type over another, increasing customer costs.

First, several parties comment that the CEC's MTR Analysis demonstrates that a mandate for natural gas capacity is not only unnecessary for reliability purposes, but would also result in a less reliable system than the portfolio of zero-emitting resources already ordered in the MTR Decision.[7] As pointed out by AEE, many of the qualitative concerns over the performance of battery storage and potential early retirement of existing gas plants raised in the CPUC Staff Paper are "speculative in nature."[8] AEE and EDF state that such concerns are not supported by the Commission's and CEC's analysis that clean energy resources have the ability to provide

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[5] *Decision Regarding Procurement to Address Mid-Term Reliability (2023-2026)* (MTR Decision), D.21-06-035 (June 24, 2021).

[6] Cal. Pub. Util. Code § 366.2(a)(5).

[7] CEC Staff Report at 13 ("[t]he scenarios with a thermal capacity NQC equivalent to replace the new zero-emitting resources, resulted in a slightly higher LOLE"); *see Peninsula Clean Energy, City and County of San Francisco, Marin Clean Energy, and Redwood Coast Energy Authority (Joint CCA Parties) Opening Comments* at 4-5; *Environmental Defense Fund (EDF) Opening Comments* at 9; *The Union of Concerned Scientists (UCS) and the Natural Resources Defense Council (NRDC) Opening Comments* at 2; *Advanced Energy Economy (AEE) Opening Comments* at 3-6.

[8] *AEE Opening Comments* at 5.

reliable capacity during peak periods in the midterm.[9] Importantly, the CEC MTR Analysis specifically concludes that (1) "[t]he ordered resource procurement for 2023 through 2026 appears to be sufficient to meet a one in ten-year loss of load expectation target, indicating system reliability," and (2) "[t]he reliance on zero-emitting resources does not appear to diminish reliability compared to procuring thermal resources."[10] The parties therefore conclude that a fossil fuel procurement mandate on LSEs is not justified.

Importantly, a fossil fuel mandate could also undermine long-term decarbonization policy goals. The Joint CCA Parties, EDF and AEE point out that by mandating the substitution of natural gas resources for renewable build including battery storage and other renewables, the Commission would be backtracking on the trajectory toward decarbonization supported by the zero-emitting resources ordered in the MTR Decision.[11]

Public Advocates Office (Cal Advocates) also urges the Commission should avoid setting rules that assign market power to specific resource types such as natural gas resources, which could inadvertently increase costs for customers.[12] Cal Advocates concludes that any natural gas capacity mandate could assign residual demand and pricing power to suppliers/counterparties.[13] In other words, by mandating that LSEs procure natural gas capacity, the Commission effectively assigns market power to a limited pool of resources (i.e., identified CAISO natural gas plant efficiency improvements and equipment upgrades in the range of 200 MW – 1,200 MW, depending on permitting and procurement/contracting issues).[14] The limited pool of available resources will limit the competition among entities to provide such resources, with the corresponding possibility of higher prices.

Parties show that evidence does not support a natural gas mandate and as discussed below, certain inputs into the analysis contained in the CPUC Staff Paper may not be justified. The Commission should thus not mandate that LSEs procure natural gas capacity.

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[9] *Id.* at 5; *EDF Opening Comments* at 8.

[10] CEC Staff Report at 2.

[11] *Joint CCA Parties Opening Comments* at 12; *EDF Opening Comments* at 9-10; *see also AEE Opening Comments* at 4 ("incremental gas plant upgrades that displace zero-emission resources would increase greenhouse gas emissions within CAISO and fundamentally run counter to California's fast-approaching power sector and economy-wide decarbonization goals").

[12] *Cal Advocates Opening Comments* at 9-10 (citing *Cal Advocates Comments on Administrative Law Judge's Proposed Preferred System Plan Ruling* (Sept. 27, 2021) at 16-18).

[13] *Id.* at 9.

[14] CPUC Staff Paper at 8.

B. Key Inputs to the RESOLVE Analysis Merit Further Refinement and Analysis

Parties express concerns over the RESOLVE analysis described in the CPUC Staff Paper. In particular, they question: (1) the cost inputs regarding natural gas capacity utilized in the RESOLVE analysis; and (2) the NQC values of resources utilized by the RESOLVE analysis. Each of these issues merits further refinement and analysis.

1. The Cost and Value Assumptions in the RESOLVE Modeling Are Not Explained or Justified

The Joint CCA Parties observe that the cost inputs to the RESOLVE analysis require further consideration.[15] In particular, the assumptions underlying the resource cost inputs should be explained, and the market value assumptions should be justified.

First, Commission Staff should publish more detail on the derivation of its resource cost assumptions. For example, it is unclear what types of costs are included (such as construction, permitting, and engineering). This information is critical in understanding the reasonableness of the RESOLVE outputs.

Second, as it stands, the upgrade costs used in the RESOLVE analysis are not sufficiently justified. The "High Cost" scenario in the analysis (i.e., the "high end" of the CEC data range (presumably the maximum value)) is $43/kW-year.[16] This value is lower than the current estimate of the cost of System Resource Adequacy (RA), which traded at approximately $62.40/kW-year in 2020 (as measured by RA-only market transactions).[17] If $43/kW-year were the true upper bound for the costs of upgrading gas generators, all or most of the generators in CAISO would presumably already have planned, or are planning, upgrades to capture RA revenue streams in the current and future RA market (in addition to the energy revenue). Indeed, the "Low Cost" figures used in the CPUC Staff Paper are likely due to the data being based on "low-hanging fruit" gas plants that already have upgrades "completed or in-progress."[18] It is likely that most generators not currently planning to upgrade are not doing so because the true cost of upgrading gas plants is higher than $43/kW-year. Therefore, the Commission should

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15 *Joint CCA Comments* at 7-8.

16 CPUC Staff Paper at 9.

17 *Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up,* issued November 2, 2020 by ED staff pursuant to D.19-10-001, Table 1. System RA is $5.20/kw-mo, or $62.40/kW-year.

18 CPUC Staff Paper at 9.

revisit its cost assumptions and confirm or deny that $43/kW-year is a fair upper estimate of cost, based on data from a larger and more representative set of generators.

If the cost values set forth in the CPUC Staff Paper are due to the expected length of a contract for RA, then the length of the contract to arrive at the "High Cost" estimate should be evaluated, and it should be determined if that contract length meets with the ten-year requirement for compliance with the MTR Decision.[19] Alternatively, if the basis for the "High Cost" $43/kW-year is the expected life of the asset, the generator will likely only offer such low pricing if a longer-term contract is signed. If the contract length is only for ten years, then it is likely that the cost per kW-year will increase significantly to avoid stranding the cost of the asset.

Third, Table 3 of the CPUC Staff Paper implies a 25-year financing lifetime for the gas resources.[20] The assumed financing lifetime is likely too long given the length of a typical gas contract, which tends to be substantially less than 25 years. For example, the data below shows contracts for CCGT2 resources from Southern California Edison's (SCE's) public 38 MMT IRP filing[21] -- all contracts listed are for ten years or less. In addition, a developer is likely to want to recover its costs more quickly than 25 years in the face of California's strong climate goals and demonstrated caution for further fossil resource reliance. CalCCA recommends that Commission Staff adjust the length of the gas financing assumptions based on what is reported for CCGT2 resources in the IRP filings.

Resource	Resource/Contract/Note	Contract Execution Date	Contract Start	Contract End	Contract Length (years)	Resource Type
BUCKBL_2_PL1X3	BUCKBL_2_PL1X3_11262-1003_none	10/29/2019	1/1/2020	12/31/2020	1.0	CAISO_CCGT2
BUCKBL_2_PL1X3	BUCKBL_2_PL1X3_11251-1002_none	10/29/2019	1/1/2020	12/31/2021	2.0	CAISO_CCGT2
BUCKBL_2_PL1X3	BUCKBL_2_PL1X3_11020_none	2/15/2007	8/1/2010	7/31/2020	10.0	CAISO_CCGT2
BUCKBL_2_PL1X3	BUCKBL_2_PL1X3_10109_none	6/28/2019	8/1/2020	12/31/2023	3.4	CAISO_CCGT2
ELSEGN_2_UN1011	ELSEGN_2_UN1011_11080_none	8/24/2010	8/1/2013	7/31/2023	10.0	CAISO_CCGT2
HARBGN_7_UNITS	HARBGN_7_UNITS_11088-1015_none	10/30/2019	1/1/2021	12/31/2021	1.0	CAISO_CCGT2
HARBGN_7_UNITS	HARBGN_7_UNITS_11088-1013_none	10/30/2019	1/1/2020	12/31/2020	1.0	CAISO_CCGT2
HARBGN_7_UNITS	HARBGN_7_UNITS_11088-1016_none	10/30/2019	1/1/2021	12/31/2021	1.0	CAISO_CCGT2
VERNON_6_MALBRG	VERNON_6_MALBRG_11251-1003_none	10/29/2019	1/1/2020	12/31/2021	2.0	CAISO_CCGT2

A financing lifetime for any natural gas expansion should not be modeled at more than ten years and, more realistically, should be modeled for a much shorter payback period.

19 MTR Decision, Ordering Paragraph 9 at 97.

20 CPUC Staff Paper at 10, Table 3.

21 Appendix E.1 Resource Data Template – SCE 38 MMT Preferred Conforming Portfolio [PUBLIC], available at https://www.sce.com/regulatory/CPUC-Open-Proceedings (R.20-05-003).

2. The NQC Values Utilized in the RESOLVE Model Must Be Reconciled

The Commission should reconcile the NQC values for all resources used in the RESOLVE model with the NQC values used in determining the MTR need, especially for gas resources and batteries. Specifically, two values warrant realignment.

First, the Commission should use Effective Load Carrying Capacity (ELCC) values for energy storage from the recent Astrape/E3 ELCC Study,[22] not the current values used in the CPUC Staff Paper (which, although not stated explicitly, presumably match what was used in the Preferred System Plan (PSP).[23] As PG&E points out, there is a mismatch between the Astrape/E3 incremental ELCC values (91 percent and 69 percent in 2024 and 2026, respectively) and the current values in the CPUC Staff Paper (73 percent and 60 percent in 2024 and 2026, respectively).[24] The values used in the CPUC Staff Paper predate the MTR Decision and are thus outdated.[25] They likely understate the reliability contribution of storage resources.

Second, the Commission should clarify why the NQC of gas is held at 99 percent throughout the lifetime of the asset.[26] NQC should degrade over time as the asset ages and forced outages increase. Even new resources can be subject to events such as thermal derates during high temperature, high load days. It is not clear how, if at all, RESOLVE handles this characteristic.[27] If the Commission assumes that NQC is maintained at a constant level, it should justify this assumption, explaining how the analysis handles forced outages.

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22 *Incremental ELCC Study for Mid-Term Reliability Procurement*, Energy + Environmental Economics (E3) and Astrape Consulting (Aug. 31, 2021) (Astrape/E3 ELCC Study), located at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20210831_irp_e3_astrape_incremental_elcc_study.pdf

23 CPUC Staff Paper at 9 ("[a]ll inputs to RESOLVE except for the gas capacity upgrade cost and potential are consistent with the proposed [PSP]").

24 *PG&E Opening Comments* at 8.

25 RESOLVE Preferred System Plan (PSP) Modeling Results at Slide 29: "Data source remains as per Inputs and Assumptions, available at: ftp://ftp.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf". The Inputs and Assumptions are from February 2020, thus making them outdated relative to the Astrape/E3 ELCC Study values.

26 *See* CPUC Staff Paper at 10, Table 3.

27 SoCalGas flags this issue with the modeling in their opening Comments. *Southern California Gas Company Opening Comments* at 2 ("SoCalGas recommends the CPUC re-examine their RA program rules and use a consistent assumption about the performance of each resource type . . . if estimated outages are to be considered, they should be considered both in the scenario construction and in the modeling assumptions in a consistent manner. For example, if assuming a 7.5% outage factor for modeling, then the natural gas resources in the scenario should have an NQC of 92.5% of nameplate capacity").

For the reasons set forth above and in party comments, Commission Staff's RESOLVE modeling which includes natural gas as a candidate resource cannot be relied upon by the Commission without further refinement and justification.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the reply comments specified herein.

Respectfully submitted,

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ASSOCIATION

October 28, 2021