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

Application of Pacific Gas and Electric Company For Adoption of Electric Revenue Requirements and Rates Associated with its 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 22-05-029 (Filed May 31, 2022)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), the California Community Choice Association [1] ("CalCCA") hereby protests the relief sought in the above-captioned *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* ("Application") .

In its Application, PG&E requests the Commission approve: (1) PG&E's forecasted 2023 energy procurement revenue requirements to become effective in rates on January 1, 2023,

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy ("PCE"), 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 ("SJCE"), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

including (a) disposition of PG&E's forecast December 31, 2022 year-end balancing account balances; (b) disposition of recorded Voluntary Allocation Market Offer Memorandum Account ("VAMOMA") balances; and (c) approval of PG&E's methodology to include 2021 and 2022 renewable energy credits ("RECs") towards the 2023 Power Charge Indifference Adjustment ("PCIA") revenue requirement calculation and to allocate the value of 2021 and 2022 RECs to benefit bundled and departing load customers responsible for applicable Portfolio Allocation Balancing Account ("PABA") vintage costs; (2) PG&E's proposed forecasted electric sales for 2023; (3) PG&E's forecast of greenhouse gas ("GHG") revenues, revenue return, and administrative, programmatic and customer outreach costs for 2023; (4) PG&E's 2021 GHG administrative and customer outreach costs as reasonable, and; (5) PG&E's rate design proposals associated with its proposed total electric procurement revenue requirements to be effective in rates on January 1, 2023, including Green Tariff Shared Renewables ("GTSR") rates.[2]

CalCCA protests the Application on the grounds that PG&E has not demonstrated the relief it requests is just and reasonable,[3] is in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes, including but not limited to Decision ("D.") 18-10-019, D.19-10-001, and D.20-12-038, and prevents illegal cost shifts between bundled and unbundled ratepayers.[4] PG&E, as the applicant, has the burden of affirmatively establishing that all aspects of the Application meet these standards.[5] That burden of proof is generally measured

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2 Application at 2.

3 *See* Cal. Pub. Util. Code § 451.

4 Cal. Pub. Util. Code §§ 366.2(f)(2), (g).

5 D.12-12-030, p. 42.

based upon a preponderance of the evidence,[6] and PG&E's Application currently does not provide sufficient evidence to meet its burden.

The Application's impact on both departed and bundled customers requires cautious and careful consideration. Although PG&E's current proposal would decrease the PCIA for all customers, including the customers of the several community choice aggregators ("CCAs") that CalCCA represents, as PG&E points out, the actual PCIA revenue requirement may change significantly over the course of this proceeding as PG&E updates its Application with actual data and revised forecasts.[7] Parties and the Commission will not know the ultimate relief PG&E is requesting in this docket, including both the revenue requirements and the final rates proposed, until, at the earliest, PG&E updates its testimony in October ("Fall Update").

Nonetheless, important work must be done prior to the Fall Update to investigate, clarify, and possibly modify and correct the following proposals, positions, calculations and issues in the Application:

- Whether PG&E's proposal to include 2021 and 2022 RECs toward the 2023 PCIA revenue requirement calculation and to allocate the value of pre-2023 RECs to benefit customers responsible for the applicable PABA vintage is reasonable;
- Whether PG&E is correctly returning the final year of the PCIA Financing Subaccount ("ERRA-PFS") credit to both bundled and unbundled customers, rather than bundled customers only, by amortizing that credit through the 2020 vintage subaccount of the PABA;
- Whether PG&E is correctly implementing D.19-11-016 and D.22-05-015 to ensure appropriate accounting treatment for both bundled and unbundled customers related

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6 *See, e.g.,* D.18-01-009, pp. 9-10; D.15-07-044, p. 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.").

7 Application at 3.

to the forecasted cost recovery of system reliability Modified Cost Allocation Mechanism (“CAM”) contracts;[8]

- Whether PG&E’s Indifference Calculation inputs and sources are appropriate and comply with D.18-10-019 and D.21-03-051;[9]
- Whether PG&E’s proposed accounting for Local RA resources forecasted to be shown or sold to the Central Procurement Entity in 2023 is reasonable and in compliance with prior Commission decisions;[10]
- Whether PG&E’s forecast of Retained RPS, Excess RPS, Sold RPS, and Unsold RPS energy is reasonable and in compliance with prior Commission decisions;[11] and
- Whether PG&E’s funding set asides for the Disadvantaged Community Green Tariff (“DAC-GT”) program and the Community Solar – Green Tariff (“CS-GT”) programs are consistent with the budgets requested by the particular CCAs.[12]

Beyond these substantive issues, Commission attention to procedural issues in this proceeding is also important. While D.22-01-023 in Rulemaking (“R.”) 17-06-026 sought to modestly extend the timeline of what is typically a truncated proceeding by requiring PG&E to file its Application by May 15,[13] PG&E sought, and the Commission’s Executive Director granted an extension, to May 31. The resulting compressed nature of this proceeding, coupled with its contentious history, the enormous revenue requirements considered, and the deep complexity of the issues addressed, all support (1) the continuation of the procedural flexibility established in prior proceedings, (2) cooperation and shortened timelines in discovery for all parties, especially following rebuttal testimony and the Fall Update, (3) contemporaneous service of workpapers with any updates to testimony, (4) clear presentation of the changes between prepared and updated

8 *See generally* PG&E Testimony at Chapter 12.

9 *See, e.g., id*. at 11-26.

10 *See generally id*. at Chapter 8.

11 *See, e.g., id*. at 11-11 – 11-21.

12 *See, e.g., id*. at 20-12.

13 D.22-01-023, Ordering Paragraph (“OP”) 3.

testimony, and (5) a willingness from all parties to meet to discuss substantive issues. CalCCA will endeavor to work with PG&E on these procedural issues as much as possible but emphasizes that timely Commission intervention on procedural matters has been necessary in past ERRA forecast proceedings.

I. CALCCA'S INTEREST

CalCCA seeks to participate in this proceeding in order to protect the interests of the CCAs it represents and the interests of those CCAs' customers. As noted above, CalCCA represents the interests of 23 CCAs in California, including 11 CCAs that serve PG&E's delivery service customers. Except for SJCE and CleanPowerSF, each of those 11 CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council. CleanPowerSF is the CCA for the City and County of San Francisco, which the San Francisco Public Utilities Commission operates. SJCE is the City of San José's CCA program, which the San José Community Energy Department administers. While CalCCA's advocacy frequently benefits both bundled and unbundled customers, the CCAs are the sole advocates for their customers and their local energy programs before this Commission.

CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from PG&E. As such, CCA customers in PG&E's service territory must pay the same electric distribution, transmission and non-bypassable rates as PG&E's bundled customers. However, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to increase electric vehicle use, procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation, and achieve other local goals.[14] CCA and other unbundled customers are also subject to several non-bypassable charges, including the PCIA and CAM, the 2023 levels of which will be determined in this proceeding.

The CCAs represented by CalCCA are advocates for the customers in the local communities that formed them. Ensuring the accuracy of the PCIA and other charges CCA customers pay, planning for changes to the PCIA, and protecting customers from the rate shock that can result, is a core directive for all CCAs and essential for any load-serving entity ("LSE"). As a result of these factors, and those discussed above and below, CalCCA has a real, present, tangible and pecuniary interest in this proceeding.

II. GROUNDS FOR PROTEST

A. PG&E Has Not Adequately Supported its New Proposed REC Tracking and Accounting Methodology, and the Commission Should Rule that the Consideration of that Methodology Beyond the 2023 RPS Compliance Year is Beyond the Scope of this Proceeding.

PG&E forecasts that its bundled customer Retained RPS position will be lower than its RPS compliance target for 2023.[15] PG&E explains that a REC shortfall in one year of an RPS compliance period can be satisfied by prior year excesses, provided those prior years fell within the same RPS compliance period.[16] PG&E held excess RECs in years 2021 and 2022 and therefore proposes to apply those excess 2021 and 2022 RECs towards its 2023 compliance target because all three years fall within the 2021-2024 compliance period.[17] In its testimony, PG&E proposes a new methodology to determine how many additional RECs generated before

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14 For example, last year, PCE became the first load-serving entity in California to provide 100% greenhouse-gas free energy to each of its customers, well in advance of the State's 2045 goal.

15 PG&E Testimony at 11-13.

16 *Id*. at 11-16.

17 *Id*.

2023 but within the 2021-2024 compliance period will be applied for bundled service customer compliance as a part of the 2023 PCIA revenue requirement calculation and how those RECs will be allocated across PCIA vintages within the 2021-2024 RPS compliance period.[18] PG&E describes its new methodology as follows:

(1) For a year in which there is a net shortfall and the remaining surplus RPS balance from the prior year(s) within the applicable RPS compliance period is greater than the ERRA year shortfall, an accounting adjustment will be made only to those years.

(2) The adjustment will be weighted across the applicable RPS generation surplus years based on the remaining amount of surplus available for each year.[19]

Applying this methodology, PG&E's minimum retained RPS entry for 2023 will credit PCIA vintages 2021 and 2022 based on their weighted share of the cumulative excess across those years and debit ERRA for 4,932,817 MWh.[20] Table 11-5 in PG&E's testimony, copied below, illustrates the results of PG&E's forecasted entries.

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18 *Id*.

19 *Id*.

20 *Id*. at 11-20.

TABLE 11-5
2023 MINIMUM RETAINED RPS ENTRY

Line No.	(A) Delivery Year	(B) Pre-2023 Adjusted Net RPS Position	(C) Minimum 2023 Entry	(D) = (B + C) Post-2023 Adjusted Net RPS Position
1	2021	5,267,672	(3,296,926)	1,907,746
2	2022	2,613,749	(1,635,891)	977,858
3	2023	(4,932,817)	4,932,817	0
4	Total	2,948,604	0	2,948,604

PG&E's proposal to use excess 2021 and 2022 RECs to cover a potential shortfall in 2023, apply those RECs for bundled service customer compliance as a part of the 2023 PCIA revenue requirement calculation, and allocate those RECs across 2021 and 2022 PCIA vintages may very well be a reasonable solution to a near-term problem, to the extent that a REC shortfall in fact materializes in 2023. CalCCA notes, however, that PG&E's near-term solution hinges on the assumption that all LSEs will take their full REC allocations through the new Voluntary Allocation Market Offer ("VAMO") process described in Chapter 9 of PG&E's testimony. While that outcome may materialize, it remains possible that LSEs may elect to take less than a full allocation through the VAMO process, or that PG&E will not experience any REC shortfall in 2023, rendering PG&E's near-term solution unnecessary.

More importantly, CalCCA objects to PG&E's suggestion that the Commission should adopt its proposal as a long-term tracking and accounting "framework"[21] in this proceeding. While PG&E's proposed REC tracking and accounting methodology may be a reasonable approach to address a REC shortfall in 2023, this ERRA Forecast proceeding is the wrong venue

[21] PG&E asserts that its methodology "addresses the need for a tracking framework identified in D.20-02-047." PG&E Testimony at 11-15, fn 28.

to consider a new long-term framework. As PG&E and the other utilities have reminded stakeholders time and again, the purpose of ERRA forecast dockets is to assure timely recovery of the utilities' actual electric procurement costs, as required by Public Utilities Code Section 454.5(d)(3), among other Commission decision-mandated tasks. The approval of program costs, the appropriate rate mechanisms to recover those costs, and the allocation of those costs among different customer groups is pre-determined via authorizing Commission decisions in other proceedings and the utility's general rate case. The scope of ERRA forecasting proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules or policies.[22]

The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[23] For example, the Scoping Memo in A.17-06-005 (PG&E's 2018 ERRA Forecast application) rejected the inclusion of certain CCA-proposed changes to the PCIA ratemaking methodology, stating:

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor-owned utilities and interested parties.[24]

Fairness requires similar prohibitions be extended to consideration of PG&E's proposal as a long-term REC tracking and accounting framework. As the IOUs have argued previously, dockets like rulemakings and consolidated applications apply to all California utilities and are

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22 *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (September 12, 2013).

23 *See, e.g.,* D.18-01-009 at 10 (finding that policy issues are properly addressed in other dockets); *see also id.* at 14, Conclusion of Law ("COL") 2 and Ordering Paragraph ("OP") 2 (denying PG&E's request to modify its line loss calculation).

24 A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner,* pp. 3-4 (August 24, 2017).

noticed to, and generally include as parties, a broader set of stakeholders.[25] It is unlikely all parties with an interest in PG&E's REC tracking and accounting framework have notice of it being raised here.

PG&E itself recently represented to the Commission how narrow and ministerial the scope of ERRA forecast applications has been—and how narrow it should be going forward. In R.17-06-026, the Commission sought input into a change in the schedule for the ERRA forecasts that would replace the November Update with an October Update.[26] CalCCA argued this change should be accompanied by a corresponding change to the filing date of the applications in order to largely maintain the same pre-Update timeline for parties to understand and develop a robust record.[27]

PG&E disagreed, arguing ERRA Forecast proceedings do not include the type of policymaking that require substantial record development. "The existing schedule (*i.e.*, from June 1st to early November) is more than sufficient to litigate *what are mostly routine and non-controversial* non-Update-related aspects of the Joint Utilities' ERRA Forecast proceedings."[28] PG&E also stated it agreed with comments from another party that the ERRA Forecast proceedings "by design" should consist of "perfunctory updates" and observed that recent complications surrounding the November Update are likely indicative of "growing pains" associated with the

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25 *See* A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018) (addressing rulemakings).

26 R.17-06-026, *E-Mail Ruling Requesting Comments on ERRA Timing Proposal*, p. 5 (May 20, 2021).

27 R.17-06-026, *California Community Choice Association's Comments in Response To Staff's ERRA Timing Proposal*, pp. 4-12 (June 15, 2021).

28 R.17-06-026, *The Joint Utilities' Opening Comments on Proposed Decision Resolving Phase 2 Issues Related To Energy Resources Recovery Account Proceedings*, p. 6 (January 6, 2022) (emphasis added).

new PCIA methodology and not indicative of what it called "*routine review* of the ERRA Forecast applications."[29] PG&E also agreed that future ERRAs, including this 2023 ERRA Forecast, should "be *more routine* than have been experienced in the past two or three years."[30] PG&E should not be allowed to push through approval of a brand new framework in a "routine" and expedited proceeding.

Importantly, there is simply no bandwidth to consider a new REC tracking and accounting framework in a 6.5-month proceeding. Stakeholders lack sufficient time and resources to track down all of the answers to the several thorny legal, policy and ratemaking questions that PG&E's testimony leaves unanswered. For example:

- How did PG&E determine its RPS compliance position in 2023?
- How did PG&E determine the quantity of excess RECs in prior years (2021 and 2022)?
- What RPS benchmarks are used to value the 2021 and 2022 RECs?
- How does that compare to the price paid for those RECs in 2021 and 2022?
- How will PG&E address a REC shortfall in 2024?
- How would PG&E address a REC shortfall in 2024 if there are insufficient excess RECs from 2021 and 2022 to meet the compliance target?
- How would PG&E address a REC shortfall at the beginning of a new compliance period (*i.e.* 2025), when it would not have excess RECs from prior years within the RPS compliance period?

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29 R.17-06-026, *Reply of Southern California Edison Company (U 338-E) To Administrative Law Judge's Ruling Requesting Comments on The Market Price Benchmark Issue Date*, p. 5 (September 22, 2021) (emphasis added).

30 *Id*.

As the above questions make clear, CalCCA has endeavored since May 31 to try to find a way to try to evaluate the details of PG&E's proposal in time for intervenor testimony, and will continue to do so; but the task is tall, and it is unlikely to be accomplished within the brief timeframes required for this proceeding.

For these reasons, CalCCA respectfully requests the Commission allow in this proceeding the evaluation of PG&E's proposal to include excess 2021 and 2022 RECs toward the 2023 PCIA revenue requirement calculation and to allocate the value of pre-2023 RECs to benefit customers responsible for applicable PABA vintage costs, but rule that the adoption of PG&E's REC tracking and accounting proposal as a framework applicable beyond the 2023 RPS compliance year is outside the scope of this proceeding.

B. PG&E Should Continue to Return the ERRA-PFS Credit to Bundled *and* Unbundled Customers by Amortizing the Final Year of that Credit Through PABA Consistent with D.22-02-002.

The ERRA-PFS is a subaccount within the ERRA that tracks revenue shortfalls associated with previously-capped PCIA rates for eligible departing load customers. The Commission previously approved PG&E's proposal to amortize the ERRA-PFS balance (credit) from the 2020 PCIA revenue requirement over three years, effective 2021.[31] PG&E will amortize the final year of ERRA-PFS credits in 2023.

In D.22-02-002, the Commission agreed with the Joint CCAs, who argued that all customers who were financially responsible for the ERRA-PFS balance—and not only bundled customers—should be entitled to the associated credit.[32] Accordingly, the Commission directed PG&E to transfer the $95 million ERRA-PFS credit for 2022 to the 2020 vintage PABA

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31 D.20-12-038, COL 9, p. 37.

32 D.22-02-002, p.28.

subaccount.[33] The Commission stated: "By moving the ERRA-PFS to PABA, we promote indifference and accuracy by returning a balance to all customers who paid for it, and not only those who remain on bundled service."[34]

PG&E's Application and testimony suggest that instead of amortizing the final year of the ERRA-PFS credit through PABA, consistent with D.22-02-002, PG&E may again be proposing to amortize that credit through ERRA.[35] If so, that credit would accrue to bundled customers only, which is neither reasonable nor consistent with the Commission's decision on this very same issue in PG&E's most recent ERRA Forecast case. CalCCA will further investigate PG&E's treatment of the 2023 ERRA-PFS credit through discovery and address this issue in testimony and briefing if necessary.

C. PG&E Has Not Met Its Burden to Show the Relief Requested in its Application is Just and Reasonable and in Compliance with Commission Rules and Precedent.

CalCCA has identified numerous issues in PG&E's Application that directly and substantially impact its interest described above. The specific issues enumerated below should be considered preliminary matters that CalCCA has identified as potentially unjust and unreasonable or out of compliance with Commission rules and precedent, and requiring further record development:

- Correct implementation of D.19-11-016 and D.22-05-015 to ensure appropriate accounting treatment for both bundled and unbundled customers related to the forecasted cost recovery of system reliability Modified CAM contracts;[36]

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33 D.22-02-002, OP 5, p.54.

34 D.22-02-002, p.28; *see also id.*, COL 7, p.51 ("Transferring the ERRA-PFS amount for 2022 to the 2020 PABA vintage subaccount promotes indifference to bundled customers and is just and reasonable.)

35 *See* PG&E Testimony at 17-3.

36 *See generally id*. at Chapter 12.

- Whether PG&E's Indifference Calculation inputs and sources are appropriate and comply with D.18-10-019 and D.21-03-051;[37]

- Whether PG&E's proposed accounting for Local RA resources forecasted to be shown or sold to the Central Procurement Entity in 2023 is reasonable and in compliance with prior Commission decisions;[38]

- Whether PG&E's forecast of Retained RPS, Excess RPS, Sold RPS, and Unsold RPS energy is reasonable and in compliance with prior Commission decisions;[39] and

- Whether PG&E's funding set asides for the DAC-GT program and the CS-GT programs are consistent with the budgets requested by the particular CCAs.[40]

CalCCA is still examining the Application and reserves the right to address and protest additional issues in the course of this proceeding as they arise through further review, analysis, discovery and investigation of all aspects of the Application.

III. CATEGORIZATION OF PROCEEDING, SCOPE OF ISSUES, NEED FOR HEARINGS AND PROPOSED PROCEDURAL SCHEDULE

CalCCA agrees with PG&E's proposed classification of this proceeding as "ratesetting". While CalCCA will pursue settlement and record stipulations to the extent feasible, it is prudent to reserve a date for an evidentiary hearing to address unresolved issues of fact.

A. PG&E's List of Issues is Incomplete and Should be Expanded.

PG&E offers the following issues to be considered in its Application:[41]

1. Should the Commission adopt PG&E's request to approve 2023 ERRA Forecast revenue requirements in this Application of $1,952 million and revenue requirements of $4,486 million for 2023 ratesetting purposes all as initially forecast herein and as may be updated through the course of this proceeding including (a) disposition of PG&E's forecast December 31, 2022 year-end balancing account balances; (b) disposition of recorded VAMOMA balances; and

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37 *See, e.g., id*. at 11-26.

38 *See generally id*. at Chapter 8.

39 *See, e.g., id*. at 11-11 – 11-21.

40 *See, e.g., id*. at 20-12.

41 Application at 29-30.

(c) the application of PG&E's methodology to include 2021 and 2022 RECs toward the 2023 PCIA revenue requirement calculation and to allocate the value of pre-2023 RECs to benefit customers responsible for applicable PABA vintage costs?

2. Should the Commission adopt PG&E's 2023 electric sales forecast?

3. Should the Commission adopt the following GHG-related forecasts for 2023?

	2023 GHG-Related Forecasts and Administrative, Program, and Outreach Expenses	**Amount**
1	GHG Administrative and Outreach Expenses	$737,000
2	Customer Generation Programs	$64.4 million
3	Net GHG Revenue Return	$536.7 million
4	Semi-annual California Climate Credit	$42.58

4. Were PG&E's recorded 2021 administrative and outreach expenses of $560,000 reasonable?

5. Should the Commission approve PG&E's rate proposals associated with its proposed total electric procurement related revenue requirements, including its GTSR proposal, to be effective in rates on January 1, 2023?

Commissioner Guzman Aceves's Scoping Ruling[42] in last year's PG&E ERRA Forecast proceeding included the following issues:

1. Whether PG&E's requested 2022 ERRA Forecast revenue requirement, Cost Allocation Mechanism/New System Generation Charge ("CAM/NSGC"), PCIA, Ongoing Competition Transmission Charge ("CTC"), and Tree Mortality Non-Bypassable Charge are reasonable and should be adopted;

2. Whether the Commission should adopt PG&E's 2022 electric sales forecast;

3. Whether the Commission should adopt PG&E's GHG related forecast for 2021 of GHG allowance revenues and returns, including Administrative and Outreach Expenses, GHG administrative and outreach set-aside true-up, Customer

[42] A.21-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 3-4 (August 11, 2021) ("2021 Scoping Ruling").

Generation Program Expenses, Net GHG revenue return, and per household Semi-Annual Residential California Climate Credit;

4. Whether PG&E's recorded 2020 GHG administrative and outreach expenses of $598,000 are reasonable;

5. Whether all calculations and entries, including but not limited to CAM/NSGC, PCIA, Ongoing CTC, ERRA, ERRA-PCIA Financing Subaccount, PCIA Under-Collection Balancing Account, Non-Vintage PCIA, TMNBC, Bioenergy Market Adjusting Tariff, and GHG related items, including the funding of GHG clean energy programs, are in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes;

6. Whether the Commission should approve the rate proposal associated with PG&E's proposed electric procurement related revenue requirements, including its 2022 GTSR rate proposal;

7. Whether the Commission should approve PG&E's disposition of year-end 2021 ERRA balance, excluding deferred revenue resulting from capped vintage 2020 PCIA rates, to the 2021 vintage subaccount of the PABA;

8. Whether the Commission should approve PG&E's proposal to transfer certain public-policy procurement costs from its PABA non-vintaged subaccount to a new subaccount in the Public Policy Charge Balancing Account for recovery from all customers through the Public Purpose Program charge on a going forward basis;

9. Whether PG&E's proposal to transfer the year-end 2021 ERRA balancing account balance, less amounts associated with the ERRA-PFS, to the latest vintage of the PABA is reasonable;

10. Whether the Commission should allow PG&E to correct an error related to the 2021 Community Green Solar Tariff program set aside amount in D.20-12-038 in this proceeding;

11. Whether there are any safety considerations raised by this application; and

12. Whether the Application aligns with or impacts the achievement of any of the nine goals of the Commission's Environmental and Social Justice Action Plan.

CalCCA believes that the list of issues in Commissioner Guzman Aceves's 2021 Scoping Ruling presents a good starting place for the scope of issues to be considered in this case, modified to: (1) update certain dates and figures such as the expenses included in Issue 4 of the list from the Scoping Ruling; (2) remove certain issues that PG&E does not request in this Application and therefore are no longer relevant such as Issue 8 of the list from the Scoping Ruling; and (3) add certain issues that PG&E requests in this Application but did not request in last year's ERRA Forecast Application, such as the REC accounting issue described in Issue 1 within PG&E's list of issues to be considered.

B. CalCCA supports PG&E's Proposed Procedural Schedule.

CalCCA supports the procedural schedule described in PG&E's Application, and included below for clarity.

Event	**PG&E's Proposed Schedule Supported by CalCCA**
Application Filed	May 31, 2022
Notice of Application Appears in Daily Calendar	June 6, 2022
Protests	30 days from Notice
Reply filed	10 days from Protest
Prehearing Conference	By July 22, 2022
PAO/Intervenor testimony served	September 7, 2022
Rebuttal testimony served	September 21, 2022
Rule 13.9 Meet and Confer	September 24, 2022
Evidentiary Hearings	September 27, 2022
Opening Briefs	October 7, 2022
Reply Briefs	October 17, 2022
Update to Prepared Testimony (Fall Update) Served	October 24, 2022
Comments to Fall Update Served, proceeding submitted	November 10, 2022
Proposed Decision	November 2022
Comments on Proposed Decision	5 days after Proposed Decision
Reply Comments	3 days after comments on Proposed Decision
Final Decision	By December 15, 2022

C. Other Procedural Requests in Light of the Compressed Nature of This Proceeding.

In light of the compressed nature of this proceeding, CalCCA also requests that the Commission:

- Set the default discovery timelines for all parties to (a) five business days prior to the Fall Update, (b) three business days after rebuttal testimony, and (c) two business days after the Fall Update is filed, with exceptions from those timelines allowed in the event that PG&E requires more time due to the number or breadth of data requests;

- Require PG&E to serve public and confidential workpapers concurrently—or as close to concurrently, as possible—with all testimony supplements and updates over the course of the proceeding;

- Require from PG&E a clear presentation of modifications between its Prepared Testimony and any supplemental testimony; and

- Encourage PG&E to continue to meet with CalCCA after PG&E files the Fall Update.

IV. COMMUNICATIONS AND SERVICE

CalCCA consents to "email only" service and request that the following individuals be added to the service list for A.22-05-029 on behalf of CalCCA:

<u>Party Representative</u>

Nikhil Vijaykar
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Information-Only

Please include the CCA representative listed below on the information-only service list for this proceeding:

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V. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission set this matter for hearing to fully examine the issues discussed above.

Dated: July 6, 2022

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION IMPLEMENTING THE AFFORDABILITY METRICS

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July 8, 2022

SUMMARY OF RECOMMENDATIONS

- ✓ The California Public Utilities Commission should reject Pacific Gas and Electric Company's request to provide its affordability metrics calculation 15 business days after a rate application is filed.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THE PROPOSED DECISION
IMPLEMENTING THE AFFORDABILITY METRICS

The California Community Choice Association (CalCCA)[1] submits these Reply Comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Implementing the Affordability Metrics* (PD), issued on June 10, 2022, and *Email Ruling Granting Request for Extension of Time to File Reply Comments on Phase 2 Affordability Proposed Decision*, dated June 27, 2022.

As set forth in its Opening Comments, CalCCA supports the PD's establishment of a multi-year period of assessment on affordability metrics implementation.[2] CalCCA also supports the PD's reliance on the CalEnviroScreen tool to replace the Socioeconomic Vulnerability Index proposed in the Affordability Metrics Implementation Staff Proposal, dated November 5, 2021,[3]

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, 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 PD at 62, Conclusion of Law (COL) 17.

3 *See Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Inviting Comments on Staff Proposal on Implementation of Affordability Metrics, Attachment A,* R.18-07-006 (Nov. 5, 2021).

to ensure a wider lens of affordability is captured including both socioeconomic and environmental indicators.[4]

This Reply responds to one request made in Pacific Gas and Electric Company's (PG&E's) Opening Comments: to allow investor-owned utilities (IOUs) 15 business days after the IOU files an application requiring affordability metrics to submit such metrics to the Commission.[5] For the reasons set forth below, the Commission should reject PG&E's proposal and adopt the PD's requirement to submit affordability metrics at the time of application filing.

I. THE COMMISSION SHOULD REJECT PG&E'S REQUEST TO PROVIDE ITS AFFORDABILITY METRICS CALCULATION 15 BUSINESS DAYS AFTER AN APPLICATION IS FILED

The Commission should reject PG&E's request for an additional 15 business days following an application to submit affordability metrics.[6] PG&E cites "operational concerns" around implementing the affordability metric requirements while it is finalizing its proposal and revenue requirements supporting the underlying application.[7]

PG&E's proposed timeline fails to address the impact on intervenors and stakeholders responding to its rate setting application in compliance with Commission procedural rules. Intervenors and stakeholders typically have 30 days to submit protests and responses to rate setting applications submitted by IOUs.[8] Submitting affordability metrics 15 business days after filing an application would result in stakeholders having only approximately five business days to review PG&E's affordability metrics analysis prior to drafting and filing a protest/response.

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[4] PD at 47-49, COL 13-14.

[5] *Opening Comments of Pacific Gas and Electric Company (U 39 M) on the Proposed Decision Implementing the Affordability Metrics*, R.18-07-006 (June 30, 2022) (PG&E Opening Comments), at 2-4.

[6] *See id*.

[7] *Id.* at 2.

[8] Commission Rules of Practice and Procedure, Rule 2.6(a).

This is an unreasonable and unfair timeline to sufficiently incorporate impacts to affordability into protests and responses, especially given the importance of utilizing these metrics to address affordability concerns for ratepayers.

Instead of the Commission providing additional time for IOUs to submit metrics after an application filing, the IOUs should incorporate the work necessary to complete affordability metrics requirements into their process and schedules for developing rate setting applications. Embedding the affordability metrics within the IOUs' process also advances affordability as a primary component to the application, rather than relegating the affordability analysis to an after-the-fact exercise.

II. CONCLUSION

For the reasons set forth above, PG&E's request for 15 additional business days to submit affordability metrics after submitting an application requiring such metrics should be rejected.

Respectfully submitted,

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 8, 2022

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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.	R.17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ENERGY INDEX MPB PROPOSALS IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING REGARDING MARKET PRICE BENCHMARKS

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On behalf of
California Community Choice Association

July 8, 2022

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California Public Utilities Commision Proceedings

SUMMARY OF RECOMMENDATIONS

- ✓ The California Public Utilities Commission (Commission) should adopt the investor-owned utilities' (IOUs') proposal to modify the Energy Index (EI) calculation, as modified, to provide for review of the three-year average in the Energy Resource Recovery Account (ERRA) forecast case each time that average is proposed or updated, and to require that the IOUs provide the weighting factors in the May 15 ERRA Forecast application filing such that the only change to the EI in the October Update is the $/MWh forward market price.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ENERGY INDEX MPB PROPOSALS IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING REGARDING MARKET PRICE BENCHMARKS

The California Community Choice Association[1] (CalCCA) submits these Comments on the Energy Index (EI) Market Price Benchmark (MPB) proposals in response to the *Administrative Law Judge's Ruling Regarding MPBs* (Ruling), dated April 18, 2022, and *Procedural email re Joint IOUs' MPB Ruling Energy Index Comments Extension Request*, dated May 16, 2022.

CalCCA supports a modified version of the Joint Investor-Owned Utilities (IOUs) June 13, 2022 proposal.[2] After discussions with the IOUs, the parties agreed that the IOUs will provide the portfolio weighting factors as part of their May 15 Energy Resource Recovery Account (ERRA) applications rather than as part of the October Update. In addition, CalCCA is

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, 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 *See* R.17-06-026, *Joint Proposal of Pacific Gas and Electric Company (U 39 M), Southern California Edison Company (U 338-E), and San Diego Gas & Electric Company (U 902-E) for an Energy Index Market Price Benchmark Calculation Pursuant to Administrative Law Judge's Ruling Regarding Market Price Benchmarks*, at 5-6 (June 13, 2022) (IOU Proposal).

amenable to the IOUs' preference to include a three-year rolling average (rather than the five-year rolling average proposed by CalCCA), *provided* the three-year average methodology is subject to review in the ERRA Forecast cases to ensure stability and reasonableness.

I. THE IOUS' PROPOSAL SHOULD BE ADOPTED WITH MODIFICATIONS

CalCCA's June 13, 2022 proposal balances the objectives of increasing forecast accuracy and maintaining transparency for stakeholders and customers.[3] CalCCA bases its proposal, in part, on the need for transparency in the methodologies used to develop market price benchmarks and in opposition to the use of internal production cost modeling (as originally proposed by the IOUs) to determine the generation weighting used in the EI.[4] The use of production cost modeling lacks transparency in the volumes and prices utilized. The proposal the IOUs ultimately put forward, however, relies on portfolio weighting derived in part from the prior three years of energy revenues earned from Power Charge Indifference Adjustment (PCIA)-eligible resources in the California Independent System Operator market.[5] Use of this historical data avoids much of the opacity problem CalCCA identified in its proposal.

As a result of CalCCA's general support of the IOU proposal, CalCCA reached out to the IOUs to discuss minor revisions to further increase transparency. CalCCA proposed that the IOUs provide the weighting factors and the data supporting such weighting in their May 15 ERRA Forecast application filings, such that the only change to the EI in the October Update is the $/MWh forward market price. The IOUs have agreed to modify their proposal to provide this weighting data in the May 15 applications.

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3 R.17-06-026, *California Community Choice Association's Energy Index MPB Calculation Proposal*, at 1-9 (June 13, 2022) (CalCCA Proposal).

4 *See* R.17-06-026, *SCE Opening Comments on Ruling re Market Price Benchmark Issue Date*, at 9 (Sept. 13, 2021).

5 IOU Proposal at 6-7.

In its proposal, CalCCA recommended the use of a five-year rolling average, as opposed to the three-year rolling average proposed by the IOUs, which would have the effect of reducing the impact of any one year's change in the index. However, CalCCA is amenable to supporting the IOUs' preference for a rolling average of three years, *provided* the three-year average methodology is subject to review in the ERRA Forecast cases to ensure stability and reasonableness.

II. CONCLUSION

If the Commission finds that reform to the EI is warranted, it should adopt the Joint IOUs' proposal, with the modifications discussed herein, to ensure the benchmark balance's accuracy and transparency.

Respectfully submitted,

/s/ Ann Springgate
Ann Springgate
KEYES & FOX LLP

On behalf of
California Community Choice Association

July 8, 2022

California Community Choice Association

SUBMITTED 07/11/2022, 10:53 PM

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. **Please provide your organizations comments on the proposed approach by the CAISO for accessing out-of-state wind resources:**

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the CAISO's proposed approach for gauging interest in accessing out-of-state wind resources. CalCCA understands the origination of this process as stemming from the 2021-2022 Transmission Planning Process (TPP) in which the California Public Utilities Commission (CPUC) Integrated Resource Planning (IRP) base portfolio included over 1,000 megawatts (MW) of out-of-state wind in *either* Wyoming/Idaho or New Mexico areas that are expected to require new transmission. In the 2021-2022 TPP, the CAISO performed an economic study on the base and sensitivity scenarios provided by the CPUC. While several transmission upgrade scenarios showed positive benefits to California Independent System Operator Corporation (CAISO) ratepayers, the CAISO indicated there was not sufficient economic justification to approve any upgrades in the 2021-2022 cycle. The CAISO also indicated that it had trouble directly comparing the cost-benefit ratios due to the differing cost/cost-recovery mechanisms proposed and differing output profiles from the various regions.

CalCCA supports load-serving entities (LSEs) providing the CAISO with information about their commercial interest in accessing out-of-state wind in these regions to allow the CAISO to identify the resource adequacy (RA) potential of clean resources in different regions and compare the costs and benefits of transmission upgrades in these different regions. However, the CAISO should not require LSEs to put down a deposit along with their expressions of interest refundable upon signing a PPA. In summary, CalCCA recommends:

- The CAISO should not require LSEs to put down a deposit with their expressions of interest;
- The expression of interest should request LSEs to provide the locations and MWs in which they see opportunities to contract with out-of-state wind resources for resource adequacy, along with supporting information as available;
- If the CAISO does move forward with a deposit requirement, the CAISO should (1) include an additional condition for the refund in which, in the event the transmission project does not get built, and as a result, the LSE does not sign a

power purchase agreement (PPA), the LSE would still receive a refund, and (2) clarify where the money will go if the CAISO does not refund it; and

- The CAISO should clarify when and how it will use expressions of interest in coordination with the typical TPP processes to drive transmission projects.

Given this is a new process with potentially significant impacts on transmission build and RA procurement, it is critically important that the CAISO establish a process that will gain the most complete picture of commercial interest in out-of-state resources and that stakeholders understand how the CAISO will use the results of the expressions of interest to drive transmission build in the context of the existing transmission planning process.

2. Please provide your organizations specifics comments on Proposal A, including the level of commitment proposed:

The CAISO proposes that LSEs put down a refundable deposit of $10,000 MW with their expression of interest in Idaho wind that the CAISO would refund upon LSE submission of a finalized PPA with the Idaho resources for the MW of capacity consistent with what they intend to procure for resource adequacy. The CAISO should not require LSEs to put down a refundable deposit with their expression of interest for several reasons. *First*, there is uncertainty inherent within transmission planning around how this process will result in actual project approvals. This means that while an LSE may express interest in a project and put down a deposit, the transmission project may still not get built. In this case, it would not make sense for an LSE to execute a PPA for resources not deliverable to California. If the LSE would not receive its deposit back from the CAISO in this case, LSEs may be unlikely to place a deposit in the first place when such a deposit is at risk from both the developer moving forward with a PPA and the CAISO approving and building the transmission line. There are too many dependencies involved with getting new transmission built to make the expression of interest dependent upon signing a PPA – California approval, other states' approvals, siting, and permitting issues can all play a role in the project progressing through to completion. *Second*, because LSEs did not submit the transmission project as an economic study request in the 2021-2022 TPP, it is unclear why the CAISO would require LSEs to put down deposits. Doing so places the burden of proof that the transmission will be used to serve CA load on the wrong entity. *Third*, it is unclear why the CAISO would require a deposit for proposal A but not proposal B. It appears to be because Idaho wind would be accessed through a project approved through the TPP as an economic study in the 2021-2022 TPP, while the wind in other areas would be accessed through projects using the subscriber model. However, under both proposals, the CAISO says, "…if there is keen interest and commitment on behalf of the LSEs along with proven benefits to California ratepayers, then the ISO would further explore the potential of adding a particular transmission project to the rate base and operating the transmission line as a participating transmission owner (PTO) in the CAISO footprint."[1] This indicates the projects would be funded and operated in the same manner regardless of the original nature of the request. *Fourth*, it creates an imbalance in the requirements for expressions of interest in proposal A versus proposal B. The CAISO should align the manner in which LSEs express interest in proposal A and proposal B so that the CAISO can obtain a clear view of actual LSE commercial interest without imposing unnecessary barriers to expressing interest.

Instead of a deposit, the CAISO should request that LSEs confidentially provide the following information with their expressions of interest to allow the CAISO to assess the level of commercial interest in each area:

- The locations and MWs in which LSEs see opportunities to contract with out-of-state wind resources for resource adequacy;
- Potential transmission projects that CAISO should prioritize in its review that would allow California to access the resources the LSEs see opportunities with; and
- Supporting information as available. Such information could include:
    - Letter of intent or attestation of interest;
    - Exclusivity agreement;
    - Term sheets;
    - PPA proposals from OOS resources;
    - Whether or not the availability of transmission will be a condition for signing a PPA; and
    - Whether or not additional Maximum Import Capability (MIC) will be a condition for signing a PPA.

If the CAISO does move forward with a proposal to require a deposit with the expression of interest, the CAISO should clarify what happens to the deposit if an LSE does not sign a PPA following the expression of interest. It appears the CAISO will only refund a deposit if the LSE signs a PPA, but the proposal does not explain what happens to the deposit if the LSE does not sign a PPA. Since the CAISO is a non-profit public benefits corporation, the CAISO must use the revenues received or pay them out to market participants. Nowhere in the proposal does the CAISO highlight how this will happen. The CAISO should also include an additional condition for the refund in which, in the event the transmission project is not built, and as a result, the LSE does not sign a PPA, the CAISO would still refund the deposit to the LSE.

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[1] CAISO Whitepaper at 6 and 7.

3. Please provide your organizations specific comments on Proposal B:

Beyond the clarifications requested in (2) and (4) related to the different approaches for Proposal A versus Proposal B and how the results of the expressions of interest will result in project approvals, CalCCA has no additional comments on Proposal B at this time.

4. Please provide any additional comments your organizations would like to make to help inform the CAISO and this initiative:

inform the CAISO and this initiative: *

The CAISO should further explain how it will use expressions of interest for both Proposal A and Proposal B to drive the approval of transmission projects. Specifically, will the CAISO consider the resource potential of other resource types (beyond just wind) that exist out of state in similar locations? To assist in this endeavor, the CAISO could expand the expressions of interest to glean information about where LSEs are seeing potential opportunities for other resources beyond wind that could use the same transmission path. Additionally, how will the results of the expressions of interest interact with the CAISO's standard planning assessments undertaken in each TPP cycle (*i.e.,* the reliability, economic, and policy assessments)? In the economic assessment in the 2021-2022 TPP, the CAISO found insufficient economic justification to move forward with the projects. How will the CAISO use the results of the expressions of interest to supplement the existing economic or policy-driven study results from the 2021-2022 TPP to decide which projects to add to the rate base?

California Community Choice Association

SUBMITTED 07/20/2022, 02:35 PM

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide your organization's comments on the CPUC's higher levels of electrification for use in the 2022-2023 Transmission Planning Process (TPP):

On July 1, 2022, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) submitted a joint Transmittal Letter to the California Independent System Operator Corporation (CAISO) for the 2022-2023 Transmission Planning Process (TPP) High Electrification (HE) Portfolio, in which the CPUC and CEC requested the CAISO update its 2022-2023 TPP Study Plan to:

1. Use the 2021 Integrated Energy Policy Report (IEPR) Additional Transportation Electrification scenario as its load assumptions for 2022-23 TPP base and sensitivity case studies;
2. Study the 30 million metric ton (MMT) HE policy-driven sensitivity portfolio transmitted as in the 2022-23 TPP HE Sensitivity Scenario; and
3. Continue studying the deliverability needs and corresponding transmission needs related to out-of-CAISO long-lead time resources, such as out-of-state wind and geothermal resources, beyond the CAISO's balancing area authority.[1]

As described in the sections below, California Community Choice Association (CalCCA) supports each of these recommendations. As the state continues down the path of higher levels of electrification and renewable integration, it is critical the CAISO TPP inform the state of the new transmission infrastructure needed to achieve reliability and policy objectives.

[1] http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf.

2. Please provide your organization's comments on the CEC's development of higher electrification grid planning scenarios:

CalCCA supports use of the 2021 IEPR Additional Transportation Electrification scenario as the load forecast assumptions for the 2022-2023 TPP base and sensitivity case studies. Assuming HE and EV scenarios will better align the load forecast with the state's carbon-neutrality goals and goals that all in-state sales of new passenger cars and trucks will be zero-emission by 2035.[1]

[1] Cal. Executive Order N-79-20.

3. Please provide your organization's comments on the CPUC's high electrification policy-driven sensitivity portfolio:

CalCCA supports use of the CPUC's HE policy-driven sensitivity portfolio in the CAISO's 2022-2023 TPP policy studies. In comments to the Preferred System Plan (PSP) in the CPUC's Integrated Resource Planning (IRP) proceeding (R.20-05-003), CalCCA recommended the CPUC commit to using the 30 MMT scenario in the next IRP process to continue the progression of lowering the GHG target in future years.[1] Including the CPUC's HE policy-driven sensitivity portfolio as a sensitivity study in the TPP will support this progression and allow for the necessary time to plan for a lower GHG target with HE.

This portfolio includes 600 additional megawatts (MW) of geothermal resources with the purpose of studying within the TPP, the transmission needs of interconnecting geothermal resources. CalCCA supports including additional geothermal in the sensitivity portfolio for study in the TPP, and has commented previously on geothermal resource potential in Northern Nevada that will be required to fulfill the CPUC's requirements for clean firm resources in the mid-term reliability procurement orders.[2] Studying additional geothermal resources in the TPP as soon as possible is crucial because these resources will require the CAISO to evaluate the potential need for expanding maximum import capability (MIC) and will likely require transmission upgrades.

[1] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan*, CPUC Rulemaking (R.) 21-05-003 (September 27, 2021) at 14.

[2] https://stakeholdercenter.caiso.com/Comments/AllComments/f19a7845-cd76-4d0c-9ebf-041832dbbe23#org-93e17ef0-4df0-49b2-b29b-67f80a1459a4.

4. Please provide you organization's comments on the CAISO's update to the 2022-2023 study plan assumptions:

CalCCA supports the CAISO's updates to the 2022-2023 final study plan assumptions, which incorporate the CEC's 2021 IEPR Additional Transportation Electrification scenario as the demand forecast and the CPUC's HE policy-driven sensitivity portfolio.

CalCCA also supports the CPUC and CEC's recommendation that the CAISO continue studying the deliverability needs and corresponding transmission needs related to long-lead time out-of-state resources, such as wind and geothermal. The ability to obtain MIC is a key contributor to load-serving entities' (LSEs') willingness to contract with an out-of-state resource because MIC is required for use of the resource as RA capacity. Therefore, CalCCA supports additional study of deliverability needs and corresponding transmission needs that will affect the ability of long-lead time resources to be used as RA. Because LSEs must secure MIC at the right nodes to be able to use out-of-state resources like Nevada geothermal to provide RA capacity, they must be able to understand how projects in the transmission plan will affect import capability at specific nodes. The CAISO should provide data on deliverability or other technical limitations that would impact deliverability and available MIC at specific branches to minimize the risk of uncertainty around available MIC.

5. Please provide your organization’s comments on the CAISO’s study plan for the high electrification special/sensitivity study:

See response to #4.

6. Please provide your organization’s comments on the CAISO’s study plan for the reduced reliance on Aliso Canyon gas storage special study:

CalCCA has no comments at this time.

7. Please provide any additional comments that your organization has:

CalCCA has no comments at this time.

DOCKETED	
Docket Number:	21-OIR-03
Project Title:	2022 Load Management Rulemaking
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Submitted On: 7/21/2022
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on the Proposed Revision to the Load Management Standards

Additional submitted attachment is included below.

STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED REVISIONS TO THE LOAD MANAGEMENT STANDARDS (NOTICE OF SECOND 15-DAY PUBLIC COMMENT PERIOD)

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July 21, 2022

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STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED REVISIONS TO THE LOAD MANAGEMENT STANDARDS (NOTICE OF SECOND 15-DAY PUBLIC COMMENT PERIOD)

The California Community Choice Association[1] (CalCCA) submits these Comments pursuant to the Notice of Proposed Action (NOPA) with proposed amendments to the Load Management Standards (LMS), California Code of Regulations (CCR), Title 20, Division 2, Chapter 4, Article 5, dated December 24, 2021; and Notice of Second 15-Day Public Comment Period, Proposed Revisions to the Load Management Standards, dated July 8, 2022 (Second Notice).

I. INTRODUCTION

CalCCA appreciates the continued efforts of the California Energy Commission (Commission) to address stakeholder concerns set forth in comments on the proposed Load Management Standard (LMS) regulations. Of particular concern, however, is that the core jurisdictional issues raised by CalCCA in its comments have not been addressed.[2] Specifically, the

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, 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] *See Comments of the California Community Choice Association to the California Energy Commission on the Draft Staff Report,* Docket 19-OIR-01 (June 4, 2021) (CalCCA June 4, 2021 Comments); *California Community Choice Association's Comments on the Proposed Amendments to the Load Management Standards Contained in the California Code of Regulations, Title 20,* Docket 21-OIR-03 (Feb. 7, 2022) (CalCCA Feb. 7, 2022 Comments); *California Community Choice Association's*

Commission lacks jurisdiction: (1) to mandate community choice aggregator (CCA) participation in the LMS, and (2) to require CCAs to adopt the prescribed marginal cost rates. While the Commission claims jurisdiction to mandate CCA participation in the LMS pursuant to Public Resources Code (PRC) section 25403.5, the explicit and clear language of the statute, as well as the legislative history, confirm that the Legislature did not intend for CCAs to be included.[3] In addition, the Commission concedes that it lacks authority to mandate CCA rates given Assembly Bill (AB) 117's grant of exclusive authority to CCA local governing boards to approve rates.[4] However, the Final Staff Report states that the LMS does not mandate rate design but rather prescribes "overarching structural features" of rates for which the Commission claims it has the authority to mandate.[5] To the contrary, nothing could be closer to rate design than, as the Commission proposes, requiring CCAs to implement *hourly variable* rates based not only on marginal costs, but *specific marginal costs*. Mandating these detailed elements of rate design encroaches on the ratemaking authority of CCA governing boards.

The Commission's beneficial goals for its regulations do not justify this unlawful encroachment. The regulations aim to "form the foundation for a statewide system of granular time and local dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid."[6] The Commission has set its sights on adoption by certain load-

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Comments on the Proposed Revisions to the Load Management Standards, Docket 21-OIR-03 (Apr. 20, 2022) (CalCCA Apr. 20, 2022 Comments).

3 *See* Herter, Karen and Gabin Situ, 2021. *Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01.* California Energy Commission, Publication Number: CEC-400-2021-003-SF (Final Staff Report) at 16-17.

4 *Id.* at 17.

5 *Id.*

6 *Id.*, Abstract at iii.

serving entities (LSEs), including CCAs, of hourly locational marginal cost rates.[7] A beneficial goal, however, does not justify an overreach of jurisdictional authority. Moreover, the Commission has another option – a voluntary program that allows local governing boards to determine how they will address real-time rates – but has rejected this approach. For the reasons set forth below, the Commission should either remove CCAs from the application of the LMS regulations, or make CCA participation voluntary:

- The Commission lacks statutory authority, under Public Resource Code section 25403.5 or any other statute, to mandate CCA participation in the LMS program;
- The Commission's requirement that CCAs adopt its prescription rate design for hourly locational marginal cost rates infringes on CCA exclusive ratemaking authority established in 2002 by AB 117; and
- Even if the Commission modifies the LMS to allow CCA participation on a voluntary basis, CCAs cannot implement an hourly locational marginal cost-based rate until the IOUs develop the data and billing systems to incorporate that rate.

II. THE COMMISSION DOES NOT HAVE STATUTORY AUTHORITY TO MANDATE CCA PARTICIPATION IN ITS LOAD MANAGEMENT STANDARDS

As explained in detail in CalCCA's prior comments, the Commission's interpretation of PRC section 25403.5 to include CCAs in the LMS constitutes legal error.[8] Section 25403.5 provides that "[t]he commission shall . . . adopt standards by regulation for a program of electrical load management for each utility service area."[9] "Service Area" is defined as "any contiguous geographic area serviced by the same electric utility."[10]

[7] On the other hand, electric service providers (ESPs) and publicly owned utilities (POUs) other than LAWDP and SMUD are not mandated to comply with the LMS, despite their serving a substantial portion of the load. *See* CalCCA April 20, 2022 Comments, at 9.
[8] *See* CalCCA June 4, 2021 Comments at 3-5; CalCCA Feb. 7, 2022 Comments at 5-8; CalCCA Apr. 20, 2022 Comments at 2-4.
[9] Cal. Pub. Res. Code § 25403.5(a).
[10] *Id.* § 25118.

The Final Staff Report cites as support for its inclusion of CCAs that:

1. CCAs operate within the geographical service territories of electric utilities, and therefore the load management standards apply to CCAs that provide electricity to customers within these service areas;

2. For the load management standards to function in a manner that meets the intent of the statute, the standards must apply to most electric customers; and

3. To the extent CCA service is the default provider and continues to expand in California, any other interpretation would diminish the effectiveness of the proposed amendments . . . and defeat the purpose of the statute.[11]

As set forth more fully below, the Commission's interpretation of section 25403.5 is inconsistent with the laws of statutory construction.

Any final interpretation of a statute is a question of law and rests with the courts.[12] In fact, a California court has specifically found that a Commission decision construing PRC sections 25500 and 25123 issued many years after the passage of the statute is *not* entitled to great weight.[13] Accordingly, proper statutory construction requires a review of methods utilized by courts to determine statutory meaning.

First, the California Supreme Court requires courts to look to "ascertain the intent of the Legislature so as to effectuate the purpose of the law."[14] A court must look first to the *explicit language*, explained as:

> the words of the statute themselves, giving to the language its usual, ordinary import and according significance, if possible, to every word, phrase and sentence in pursuance of the legislative purpose. A construction making some words surplusage is to be avoided. The words of the statute must be construed in context, keeping in mind the statutory purpose,

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11 Final Staff Report at 17.

12 *Department of Water and Power, City of Los Angeles v. Energy Resources Conservation and Development Commission,* 2 Cal.App.4th 206, 296-297(1992) (rejecting the Commission's contention that the appellate court must defer to its administrative interpretation of Public Resources Code sections 25500 and 25123 when although its interpretation was a case of first impression, the decision was issued in 1990 interpreting a 1974 statute and therefore was not a "contemporaneous construction of a new enactment by the administrative agency charged with its enforcement" which would be entitled to "great weight") (citing *Dyna-Med, Inc. v. Fair Employment & Housing Commission* (1987) 43 Cal.3d 1379, 1388)).

13 *Ibid*.

14 *Dyna-Med, Inc.*, 43 Cal.3d at 1386.

> and statutes or statutory sections relating to the same subject must be harmonized, both internally and with each other, to the extent possible.[15]

Here, the Commission's expansive interpretation of PRC section 25403.5 to include CCAs based on its hopes for success with the Market Informed Demand Automation Server (MIDAS) system and the proposed amendments places the cart before the horse. The explicit statutory language specifically allows the Commission to adopt LMS for each "utility service area," and the definition of "utility" does *not* expressly incorporate CCAs.[16]

In addition, the *context* of section 25403.5's adoption in 1976, when the LMS were adopted as a requirement for a utility prior to siting a new power plant, demonstrates that the LMS are intended to apply only to utilities.[17] CCAs were not created until 2002, and therefore the original enactment of PRC section 25403.5 did not include CCAs. The context has also changed dramatically, from all generation being built by regulated utilities (as was the case in 1976), to a generation market where the utilities, other LSEs, and developers procure, build, and own generation. Perhaps most importantly, CCAs have never been added as an entity subject to its requirements.

In addition, consideration of *all* of the language in PRC section 25403.5 suggests that the Commission's ability to consider any adjustments to rate structure as a load management technique applies *only* to entities subject to rate jurisdiction of the California Public Utilities Commission (CPUC).[18] CCA rates are not approved or regulated by the CPUC, but rather by CCA local

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15 *Id.* at 1386-87 (citations omitted).

16 Cal. Pub. Res. Code §§ 25108 (definition of "electric utility), 25118 (definition of "service area").

17 AB 4195 (1976).

18 *See, e.g.,* Cal. Pub. Res. Code § 25403.5(a)(1) (allowing the Commission to consider adjustments in rate structure as a load management technique, but stating that "[c]ompliance with those adjustments in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service"); *see also* Cal. Pub. Res. Code 25403.5(b) (requiring that the LMS be "cost-effective when compared with the costs for new electrical capacity" and that "[a]ny expense or any capital

governing bodies.[19] Therefore, harmonizing the statutory language clearly demonstrates that CCAs, not subject to CPUC ratemaking authority, were not meant to be included within the reach of PRC section 25403.5.

Second, even if the explicit meaning of a statute remains uncertain, the Court requires a review of the legislative history to determine the legislative intent.[20] Here, the explicit language is *not* uncertain, as described above. However, a review of the legislative history of PRC section 25403.5, which includes amendments up through 2002, further demonstrates that the Legislature *did not intend* for CCAs to be included within the statute's reach. In fact, the legislative history suggests that amendments to the load management standards program over time narrowed the LMS program's scope: (1) to *remove* authority from the CEC regarding penalties and requirements under the LMS; and (2) to *consolidate reporting requirements,* including those involving CCAs, in the IEPR process while removing those reporting requirements from section 25403.5.[21] Therefore, while the Legislature *could have* added CCAs to the entities subject to the Commission's LMS while it

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investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and shall be treated by the Public Utilities Commission as allowable in a rate proceeding").

19 *See Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters,* R.03-10-003 (Oct. 2, 2003) at 9, 42 (the legislature did "not require the [CPUC] to set CCA rates or regulate the quality of its services," and has "consistently treated CCAs as stand-alone operations with ratemaking discretion").

20 *Dyna-med, Inc.,* 43 Cal.3d at 1327.

21 Cal. Pub. Res. Code § 25403.5 was originally enacted to require a utility to certify that it was in compliance with the LMS before the Commission would approve sites for a new power plant to effectively coordinate new capacity with load needs. Cal. Pub. Res. Code § 25403.5(e) (1976) (amended in 1980 through AB 3062 (stats. 1980) to eliminate a penalty clause, and to add a forecast reporting requirement for electric utilities). Senate Bill (SB) 1389 (stats. 2002) shifted forecast reporting requirements to the Integrated Energy Policy Report (IEPR). Notably, the direction for electric utilities to report on load management standards was eliminated, but PRC section 25302.5(a) did allow the Commission to require in the IEPR "submission of demand forecasts, resource plans, market assessments, and related outlooks from electric . . . utilities, . . . and other market participants," including CCAs. Therefore, the IEPR process established in 2002 expressly includes CCAs, but the load management standards (adopted before the creation of CCAs) were never amended to include CCAs.

amended section 25403.5, *or* while it incorporated requirements for CCAs in other sections of the PRC, it did not.[22]

In addition, to reflect changing market structures, the Legislature has routinely updated both the PRC and Public Utilities Code to reflect and include new market participants. This includes but is not limited to the Legislature's creation of the new categories of "load-serving entities" for Resource Adequacy and "retail supplier" for the Power Content Label requirements enforced by the CEC.[23] Most recently, the Legislature adopted AB 205 which provides a specific list of entities, which include CCAs, eligible for the Demand Side Grid Support Program, administered by the Commission.[24] The Legislature has taken no similar action adding CCAs to the application of the 1976 load management standards.

According to the laws of statutory construction, PRC section 25403.5 does not explicitly or implicitly grant the Commission jurisdictional authority to mandate CCA compliance with its proposed LMS regulations. Therefore, the Commission should either remove CCAs from the regulations, or allow CCA voluntary compliance with the regulations.

III. THE COMMISSION LACKS AUTHORITY TO MANDATE CCA RATES

The Commission also lacks authority to mandate that CCAs adopt a particular rate design. The Commission acknowledges its lack of "exclusive or independent authority" to require CCA adoption of a particular rate. However, it insists that the rate required by the proposed LMS

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22 *See Gikas v. Zolin* (1993) 6 Cal.4th 841, 852 (citing the maxim of statutory construction, *expressio unius est exclusion alterius* – that "[t]he expression of some things in a statute necessarily means the exclusion of other things not expressed"); *see also Dyna-Med, Inc.,* 43 Cal.3d at 1391 (stating that the *expression unius* doctrine can be used as a guide when a statute is ambiguous).

23 *See* Cal. Pub. Util. Code § 380 (establishing that the California Public Utilities Commission shall establish RA requirements for *all* load-serving entities, including CCAs); *see also* Cal. Pub. Util. Code § 398.2 (including CCAs within the definition of a "Retail Supplier" subject to the power content label requirements).

24 Cal. Pub. Res. Code § 25792(b).

regulations is simply a "rate structure" and CCA governing boards retain ultimate approval authority.[25] However, as discussed in CalCCA's prior comments, the proposed regulations go far beyond a "rate structure." A rate "structure" could be, for example, time-differentiated rates, leaving LSEs the flexibility to design rates that meet this objective. What the regulations propose to do -- requiring an hourly variable rate using specific marginal costs – steps into the scope of "rate design." Furthermore, the Commission retains ultimate enforcement authority for failure to comply with the regulations.[26] As a result, even if the Commission has jurisdiction to require CCA compliance with the LMS (which it does not), the proposed regulations constitute an unlawful infringement on CCA ratemaking authority provided by AB 117.

IV. EVEN IF THE COMMISSION SEEKS VOLUNTARY PARTICIPATION BY CCAS IN ITS LOAD MANAGEMENT PROGRAM, THE CURRENT STANDARDS ARE CURRENTLY TECHNOLOGICALLY INFEASIBLE

Finally, if the Commission seeks voluntary CCA participation in its LMS given its lack of statutory authority to mandate CCA participation, implementation of the regulations is currently technologically infeasible for CCAs. As explained in prior CalCCA comments, CCAs cannot implement an hourly locational marginal cost-based rate until the IOUs develop the data and billing systems to incorporate the CCA rate.27 For CCA customer bills, the IOUs receive from the CCAs the generation rate information to incorporate into the bills, and the IOUs then send the bills out incorporating their transmission and distribution rates. Therefore, until the IOUs establish their own data and billing systems to implement the LMS, CCA customers will not be billed for the CCA generation portion and cannot even voluntarily participate in the LMS.

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[25] Final Staff Report at 17.

[26] *See* CalCCA Feb. 7, 2022 Comments at 8-10.

[27] *See* CalCCA April 20, 2022 Comments at 6-7.

V. CONCLUSION

For the reasons set forth above, CalCCA requests that the Commission either remove CCAs from the proposed LMS regulations or allow voluntary participation in the LMS.

Respectfully submitted,

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 21, 2022

California Community Choice Association

SUBMITTED 07/25/2022, 02:18 PM

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide a summary of your organization's comments on the WEIM Resource Sufficiency Evaluation Enhancements Phase 2 straw proposal and July 11, 2022 stakeholder call discussion:

The California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the California Independent System Operator Corporation's (CAISO's) WEIM Resource Sufficiency Evaluation Enhancements Phase 2 Straw Proposal, dated July 1, 2022 (Straw Proposal), and the July 11, 2022 stakeholder call. The enhancements to the resource sufficiency evaluation (RSE) adopted in Phase 1, and the proposed accuracy enhancements proposed in the Straw Proposal Section 4, demonstrate the CAISO's commitment to increasing accuracy of the RSE by reducing failures based on false indicators. CalCCA supports the CAISO's proposed accuracy enhancements set forth in the Straw Proposal.

In addition, CalCCA supports the CAISO's proposal to allow balancing authority areas (BAA) to elect to utilize energy assistance through the Western Energy Imbalance Market (WEIM) to cure resource insufficiencies. CalCCA's concern with this proposal lies with ensuring appropriate consequences faced by a BAA for misuse of the energy assistance option. The following provides CalCCA's comments on (1) consequences for misuse of the energy assistance option; (2) allocation of assistance energy revenue; and (3) oversupply failure consequences.

A. Consequences for Misuse of Energy Assistance Option

The Straw Proposal poses two questions in section 5.1.1 to gauge what constitutes "misuse" and how to construct appropriate consequences for such misuse. First, the Straw Proposal asks about the relationship between many small failures (i.e., a 1 megawatt (MW) failure for 3 straight hours) and fewer large failures (a 40 MW failure during a single interval). While both failures are potentially significant, CalCCA views a larger failure during a single interval to be an immediate and significant risk indicating a substantial failure of a BAA. Consequences are necessary to deter such failures. Smaller failures indicate a higher risk tolerance than the CAISO should accept, demonstrating that they frequently secure just enough (and in some instances, not enough) supplies. Such failures should face consequences given the likelihood of (and to prevent) additional failures and to incentivize a change in practices.

Second, the Straw Proposal asks whether failures during varying system conditions represent the same level of functionality, and if not, is weighting the impact of failures during varying conditions appropriate. Failures during tight conditions immediately place the system in jeopardy, and therefore failures during different system conditions do not represent the same level of functionality and should face different consequences.

B. Allocation of Assistance Energy Revenue

Section 5.1.3 of the Straw Proposal requests feedback on two proposed methods for allocating the energy assistance revenue – i.e., revenue separate from the conventional congestion revenue and collected only after the activation of the hurdle rate. The two proposals are to allocate the revenue: (1) pro rata by net WEIM export to entities that have passed the RSE; or (2) pro rata to entities that have passed the RSE (whether dispatched or not). While the CAISO is leaning towards the first option, CalCCA supports allocating revenue to all entities that have passed the RSE, including those not dispatched. Entities passing the RSE, and whose capacity is available to cure resource insufficiencies, should be rewarded for bidding their capacity into the WEIM. Conceptually, the CAISO should encourage all capacity to be made available to the market. Awarding energy assistance revenue based upon all capacity available to the WEIM from entities passing the RSE is more effective in this regard than just the select entities that clear the energy market since this would be energy based rather than capacity based.

C. Oversupply Failure Consequences

The CAISO proposes that during oversupply conditions, a failure of the ramping sufficiency test allows incremental additional export transfers at a hurdle rate of $0/megawatt-hour. CalCCA supports the CAISO's proposal, which introduces an economic solution to discourage curtailment of low-cost supply in the WEIM.

Finally, CalCCA supports the CAISO's characterization of the proposed changes (excluding the CAISO export tagging rules) to the RSE as under the joint authority of the WEIM Governing Body and the Board of Governors.

2. Provide your organization's comments on the proposal to align the ISO BAA WEIM RSE obligations with those of other EIM participating BAA's, specifically the ISO's proposal to only count export schedules it can confidently support:

No comments at this time.

3. Provide your organization's comments on the proposal to adjust a WEIM BAA's ability to show low priority exports on a base schedule; if the ISO BAA has the low priority exports removed from its WEIM RSE obligation:

No comments at this time.

4. As discussed on the stakeholder call, the ISO would look to discount from its WEIM RSE obligations low priority exports that may have been supported by an import schedule that was ultimately not tagged. The tag information is not known until T-40. Do WEIM entities believe that discounting the ability to count these low priority exports in their base schedules is appropriate? Does the

window between the existing T-40 RSE and the proposed binding T-30 RSE provide sufficient time to update base schedules?

No comments at this time.

5. **Provide your organization's comments on the ISO's proposal to change the tagging rules for low priority exports:**

No comments at this time.

6. **Provide your organization's comments on whether it is it appropriate for the ISO as the market operator to validate, review and potentially discount interchange supply shown within an WEIM BAA's base schedule based upon the e-tags that support the shown interchange:**

No comments at this time.

7. **Provide your organization's comments on the ISO's proposal to utilize the quantile regression methodology to inform the uncertainty requirement that is tested for in the WEIM RSE's capacity and flexible ramping sufficiency tests:**

No comments at this time.

8. **Please provide your organization's input on the ISO's proposal to permanently remove the adder for intertie uncertainty:**

No comments at this time.

9. **Please provide your organization's input the potential to implement energy assistance through the WEIM prior to summer 2022:**

No comments at this time.

10. **Please provide your organization's input on the ISO's proposal to modify the consequences of failing the WEIM RSE to provide the opportunity to cure over and undersupply conditions through the WEIM:**

No comments at this time.

11. **Provide your organization's comments on the ISO's proposal to cure undersupply conditions using a hurdle rate set at the bid cap:**

No comments at this time.

12. **Provide your organization's comments on the ISO's proposed revenue allocation for assistance energy revenue:**

No comments at this time.

13. **Provide your organization's comments on the ISO's proposal to relax export limitations for an EDAM BAA that has failed the flexible ramping sufficiency test using a hurdle rate set to $0:**

No comments at this time.

14. Provide your organization's comments on relaxing import limitations to a BAA that has failed the WEIM RSE in the upwards direction while the conditions in question 8 have been met:

No comments at this time.

15. Provide any additional comments on the WEIM Resource Sufficiency Evaluation Enhancements Phase 2 straw proposal or July 11, 2022 stakeholder call discussion:

No comments at this time.

DOCKETED	
Docket Number:	22-RENEW-01
Project Title:	Demand Side Grid Support Program
TN #:	244247
Document Title:	CalCCA CommeCalCCA Comments on Proposed Guidelines 07 29 22
Description:	N/A
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STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

IN THE MATTER OF: Demand Side Grid Support Program (Assembly Bill 205, 2022)	Docket No. 22-RENEW-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DRAFT PROGRAM GUIDELINES – DEMAND SIDE GRID SUPPORT (DSGS) PROGRAM, FIRST EDITION

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July 29, 2022

STATE OF CALIFORNIA ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

IN THE MATTER OF: Demand Side Grid Support Program (Assembly Bill 205, 2022)	Docket No. 22-RENEW-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DRAFT PROGRAM GUIDELINES – DEMAND SIDE GRID SUPPORT (DSGS) PROGRAM, FIRST EDITION

The California Community Choice Association (CalCCA)[1] appreciates the opportunity to provide comments on the Draft Program Guidelines for the Demand Side Grid Support (DSGS) Program (Draft Guidelines).[2] CalCCA proposes a modification to the Draft Guidelines to resolve an ambiguity regarding eligibility criteria, which could prevent California from realizing the intended reliability benefits of the DSGS Program.

The statute underlying the Draft Guidelines creates an ambiguity in determining which customers and retail sellers may participate in the DSGS Program. The California Energy Commission's (Commission) proposal carries the statutory ambiguity into the Draft Guidelines. Failure to internally harmonize the statute and resolve its interpretation in the context of policy

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, 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 CalCCA submits these Comments pursuant to the Notice of Availability and Request for Comments on Draft Proposed DSGS Program Guidelines, dated July 20, 2022.

outcomes will gravely restrict program eligibility and eviscerate the program's intended benefits. CalCCA thus requests modification of the Draft Guidelines to make clear that all customers – regardless of the retailer seller who serves them – may participate in the DSGS Program as long as they do not engage in "dual participation" in another California Public Utilities Commission (CPUC) administered program.

Public Resources Code (PRC) section 25792(b), enacted by Assembly Bill (AB) 205, provides as follows:

> Eligible recipients shall include all energy customers in the state, except those that are eligible to participate in demand response or emergency load reduction programs offered by entities under the jurisdiction of the Public Utilities Commission.[3]

Virtually all customers of an investor-owned utility (IOU), a community choice aggregator (CCA), and an Electric Service Provider (ESP) "are eligible to participate" in one or more CPUC-administered demand response or emergency load reduction programs. A literal reading of this language thus would suggest that since they are all eligible for CPUC-administered programs -- whether or not they actually participate -- no IOU, CCA, or ESP customers are eligible to participate in the DSGS Program. This interpretation, however, leads to an implausible result: that the Legislature intended to apply this program *only* to customers of publicly owned utilities (POU).

Additional language in this subsection suggests this restrictive reading is not at all what the Legislature had in mind. Subparts (1)-(3) of subdivision (b) provide that payments will be made to participating "individual entities," "aggregators of multiple energy customers," and "local publicly owned electric utilities and load-serving entities." Had the Legislature intended to

[3] Cal. Pub. Res. Code § 25792(b) (emphasis supplied).

limit program eligibility to POU, it would have made no sense to permit "load-serving entities," which include IOUs, CCAs, and ESPs, to receive payments under the program.

A more inclusive reading of the statute is further supported when considering the counterproductive policy impacts of a literal interpretation of the statute. The program should aim to maximize participation in the DSGS Program to benefit reliability. In fact, IOU, CCA, and ESP customers constitute roughly 75 percent of the total load in California. By foreclosing these customers from participation, the Commission would severely limit program participation and the resulting benefits to system reliability. With a full awareness of this balance, the Legislature could not have intended this result.

The more likely statutory intent of the eligibility criteria is not to limit participation by IOU and CCA customers, but to limit dual participation in both a CPUC-administered program and the DSGS Program. "Dual participation" has long been an issue in the realm of CPUC-administered programs. Most recently, in the rulemaking addressing preparation for potential extreme weather events for Summers 2022 and 2023, the Commission addressed "dual participation" in various programs. Approving the Southern California Edison Company (SCE) Whole Home Savings Pilot, the Commission concluded: "[d]ual participation in another Demand Response program is not permitted."[4] In contrast, the Commission permitted non-residential customers enrolled in SCE's Summer Discount Program "to dual participate in [emergency load reduction programs (ELRP)]…,"[5] yet retained the "dual participation bar" in other circumstances.[6]

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4 D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023,* R.20-11-003 (Dec. 2, 2021), Ordering Paragraph (OP) 35, at 171.

5 *Id.*, OP 49 at 157.

6 *Id.* at 133.

The Draft Guidelines, if not corrected, would carry the most literal statutory interpretation into regulation. The Draft Guidelines section A.2.a state that "[c]ustomers or aggregators of a DSGS provider are eligible to receive incentives under the DSGS program if they are not…[eligible] to participate in demand response, net energy metering,[7] or [ELRP] offered by entities under the jurisdiction of the California Public Utilities Commission."[8] Section A.2.b of the Draft Guidelines adds more reasonable criterion, akin to the "dual participation" requirement; this section prohibits payments to customers receiving payment for "the same reduction in use of electricity through any other utility or state program."[9] Indeed, the guidelines make perfect sense if subpart a is eliminated and subpart b is retained.

Internal harmonization of PRC section 25792(b), particularly when considering policy impacts, requires granting DSGS program eligibility to customers of all retail sellers, provided only that they do not engage in dual participation. Consistent with this conclusion, CalCCA proposes that the Commission **strike Draft Guideline section A.2.a** while retaining section A.2.b:

> 2. Eligible Participants Customers or aggregators of a DSGS provider are eligible to receive incentives under the DSGS program if they are not:
>
> ~~a. Eligible to participate in demand response, net energy metering, or emergency load reduction programs offered by entities under the jurisdiction of the California Public Utilities Commission.~~
>
> b. Receiving payment or accounting for the same reduction in use of electricity through any other utility or state program.
>
> c. Cogeneration facilities with a power purchase agreement.

CalCCA thanks the Commission for its consideration of this important proposed change.

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7 CalCCA notes that the statute does not include a requirement associated with net metering.

8 Proposed Draft Program Guidelines, Demand Side Grid Support (DSGS Program, First Edition, Chapter 2.A.2.a) at 2.

9 *Id.*

Respectfully submitted,

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 29, 2022

AUGUST FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY OF PIONEER COMMUNITY ENERGY, SONOMA CLEAN POWER AUTHORITY, EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, AND RURAL COUNTY REPRESENTATIVES OF CALIFORNIA

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On Behalf Of:
Pioneer Community Energy
Sonoma Clean Power Authority
East Bay Community Energy
Marin Clean Energy
Rural County Representatives of California

August 5, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY OF PIONEER COMMUNITY ENERGY, SONOMA CLEAN POWER AUTHORITY, EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, AND RURAL COUNTY REPRESENTATIVES OF CALIFORNIA

In accordance with Rule 11.1(f) of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") Pioneer Community Energy ("Pioneer"), Sonoma Clean Power Authority ("SCP"), East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), and Rural County Representatives of California ("RCRC") (collectively, the "Joint Parties"), hereby submit their Reply to parties' July 27, 2022 Responses to the Joint Parties' July 12, 2022 *Motion for Consideration of Fast-Trip Program Rules in the De-Energization Rulemaking* ("Motion"). The Joint Parties were granted permission to file this Reply in ALJ Kao's July 28, 2022 email.

I. REPLY

A. The Commission Must Regulate The IOUs' Fast-Trip Programs

The Motion establishes that the Investor Owned Utilities' ("IOU") Fast-Trip programs raise issues of significant public interest that directly relate to public safety.[1] As such, the Commission

[1] Motion at 5-12.

has a statutory obligation to review and regulate these programs.[2] Both the Joint Local Governments and Center for Accessible Technology ("CforAT") support this interpretation.[3] Tellingly, none of the IOUs dispute the Joint Parties' statutory interpretation, nor do they attempt to directly refute the Joint Parties' conclusion that the Commission has a statutory obligation to regulate Fast-Trip programs.

The Commission's obligation to review and regulate the IOUs' Fast-Trip programs is underscored by facts raised in the Joint Local Governments' response. The Joint Local Governments clearly establish the scale and seriousness of the public interests implicated by the IOUs' Fast-Trip programs:

> **"**In the first six months of 2022 alone, almost as many PG&E customers have lost power from fast-trip settings as lost power from all PG&E's de-energization events in 2020, and fast-trip outages have already outstripped 2021 PG&E de-energization impacts by several orders of magnitude."[4]

The Joint Local Governments specifically highlight the shocking outage numbers reported in Pacific Gas & Electric Company's ("PG&E") June 2022 report on PG&E's Fast-Trip program, titled EPSS:

> "PG&E's fast-trip outages in the first six months of 2022 have cut power to 511,500 customer accounts, or between approximately 1 and 1.5 million individuals; 32,418 of those customer accounts are medical baseline and 22,509 are customers who use electricity-powered devices for life support."[5]

PG&E's June 2022 EPSS report states that PG&E had 425 EPSS outages affecting 478,522 customers *in the month of June 2022 alone*. This number is particularly worrying given the fact that wind speeds and other weather conditions that increase fire risk and the likelihood of vegetation and other materials contacting powerlines do not peak until mid-to-late autumn.

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2 Motion at 6. Citing California Public Utilities Code Section 2101.
3 Joint Local Governments Response at 3-4; CforAT Response at 1-2.
4 Joint Local Governments Response at 1.
5 Id. at 7-8

This many outages, affecting such a large number of customers, raise significant safety-related issues of public interest. The Motion provided an initial list highlighting some of these critical issues.[6] In their respective responses, the Joint Local Governments, California Energy Storage Alliance ("CESA"), and CforAT all identify additional safety issues and issues of significant public interest.[7] The Joint Parties agree that the issues raised by these responses are of critical importance and should be addressed by the Commission in the requested Fast-Trip phase of this Rulemaking. Together, the number of safety issues and other issues of significant public interest far exceed the critical mass needed to trigger the Commission's statutory obligation to review and regulate Fast-Trip programs.

Of particular concern to the Joint Parties is the Joint Local Governments' observation that from January to June of this year, 22,509 PG&E life support customers experienced EPSS outages. For customers that rely on electrically powered life support equipment, a power outage is a potentially fatal event. In addition, for these customers in particular, fast-trip outages are significantly more dangerous than Public Safety Power Shutoff ("PSPS") outages because fast-trip outages occur suddenly, without prior notice or warning, meaning that the customer doesn't have the opportunity to prepare for the outage by arranging relocation or evacuation, calling for medical help, starting up a generator for backup power, or charging backup batteries or battery-powered equipment. It is unclear how many of these life support customers, if any, have been provided with backup batteries by PG&E as part of PG&E's PSPS impact mitigation measures. Further, it is not clear whether PG&E made any efforts to mitigate the potentially fatal impacts of EPSS outages on these customers. Given the lack of any comprehensive post-outage impact reporting requirement for Fast-Trip outages, the severity of the impacts of such outages on vulnerable customers remains an unknown. If

[6] Motion at 8-13.
[7] Joint Local Govs Response at 4-7; CforAT Response at 2; CESA Response at 2-3.

someone died or was severely harmed due to a Fast-Trip outage, it is unclear whether the IOU, the Commission, or stakeholders would even be aware of it.

In addition, the Joint Parties note that as the IOUs reduce their reliance on PSPS in favor of Fast-Trip as their primary wildfire prevention mechanism, the amount of information available to stakeholders regarding an IOU's fire-prevention outages grows proportionately smaller, as is the portion of the IOUs' fire-prevention outages that are subject to thorough Commission oversight and regulation. There is a clear trade-off between Fast-Trip and PSPS – a Fast-Trip outage on a circuit reduces the likelihood that a PSPS outage in that area will be called. By reducing the number of reported and regulated PSPS outages and increasing the use of less transparent, effectively unregulated Fast-Trip outages, the IOUs' PSPS reporting, may be painting a significantly more positive picture than actually exists on the ground. This alone is ample reason to adopt rules that bring Fast-Trip programs up to the same level of oversight and regulation as PSPS programs.

B. Fast-Trip Programs Should Be Considered In This Rulemaking

All three IOUs argue that consideration of Fast Trip program rules falls outside the scope of this Rulemaking.[8] Each of this IOUs bases this argument on the claim that the scope of this Rulemaking is limited to *intentional outages* like PSPS outages, while Fast-Trip programs involve *unplanned* outages.[9] This argument is clearly in error and should be disregarded by the Commission.

First, as a threshold matter, the Joint Parties note that none of the IOUs cite to or quote any specific requirements from the proceeding's Order Instituting Rulemaking to support their claim that the consideration of Fast-Trip outages fall outside the scope of this proceeding.

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8 PG&E Response at 3-7; SCE Response at 3; SDG&E Response at 5-6.
9 Id.

Second, contrary to the IOUs claims otherwise, *Fast-Trip outages are intentional outages*. In their fast-trip programs the IOUs *intentionally* and *proactively* modify the sensitivity of their safety devices to increase the devices' sensitivity and lower the threshold needed to trigger an automatic outage. This is done for the express purpose of causing outages that would not otherwise occur under normal operating conditions, and with the intended result of increasing the overall likelihood and frequency of outages in order to reduce fire risk.

In claiming that Fast-Trip outages are not intentional outages, the IOUs commit a fundamental error in reasoning – claiming that their actions are not "intentionally" connected to those actions' results because of an intervening link in the chain of causation (this link being the action of automatically-triggered safety devices). With Fast-Trip, the IOUs intentionally put in place a mechanism that they know will increase the likelihood and frequency of outages, but then claim that the resulting outages are not intentional. The IOUs' position is analogous to that of a person who sets a mousetrap for the purpose of catching a mouse, knowing that the trap is likely to catch a mouse, and then, when a mouse is caught, claims that she did not intentionally catch the mouse because the trap caught the mouse automatically. The Commission should not be persuaded by this fallacious reasoning. The significant increase in outages that occur under Fast-Trip are the direct, foreseeable, and intended consequence of the IOUs act of implementing Fast-Trip by increasing the sensitivity of a circuit's safety devices.

In determining whether Fast-Trip programs are in scope, rather than focusing on the IOUs' mischaracterizations of fast-trip outages as unintentional or the other trivial differences that the IOUs raise to muddy the waters,[10] it is far more useful to focus on the fundamental similarities shared by Fast-Trip programs and PSPS programs:

- Purpose: Both Fast-Trip programs and PSPS programs share an identical purpose, the prevention of ignition events caused by energized lines.
- Customer Risks And Impacts: Both Fast-Trip outages and PSPS outages impose the same basic set of outage-related risks and impacts on customers (with Fast-Trip outages imposing additional risks due to the lack of prior notice).
- Legal Justification For Outage: While the IOUs have not explicitly asserted a legal justification for Fast-Trip outages, the only applicable exception to their duty to provide reliable and uninterrupted electric service is the same public-safety exemption used to justify PSPS outages.

Given the fundamental similarities between the Fast-Trip programs and the PSPS programs, the instant Rulemaking is the most reasonable, appropriate, and efficient venue for reviewing and regulating Fast-Trip programs.

C. The Commission Has Jurisdiction Over Fast-Trip Program Rules

SDG&E and SCE both argue that Fast-Trip Programs are overseen by the Office of Energy Infrastructure Safety ("OEIS"), thus rendering Commission-imposed rules and regulation of these programs unnecessary.[11]

These arguments are in error. Despite the creation of OEIS on July 1, 2021 the Commission retains primary jurisdiction over the safety of utility de-energization practices, including both PSPS

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10 For instance, SCE claims that its Fast-Trip program isn't a "program" and instead is a collection of engineering settings (SCE Response at 2-3), while PG&E focuses on the technical details of how fast-trip outages are triggered (PG&E Response at 6).

11 SCE Response at 4-5.

and Fast-Trip. Section 8385 specifically states that nothing in the statutory provisions establishing OEIS and defining the agency's regulatory scope (Section 8385 et. seq.) "affects the commission's authority or jurisdiction over an electrical corporation." Further, this section clarifies that the role of OEIS is to "supervise an electrical corporation's compliance with the requirements of this chapter." These requirements primarily relate to the adequacy and content of an IOU's wildfire mitigation plan. This role does not supersede the Commission's jurisdiction to regulate, oversee, and adopt rules governing the IOUs' de-energization programs, including both PSPS and Fast-Trip.

II. CONCLUSION

The Joint Parties thank the Commission for its consideration of this Reply.

Respectfully Submitted,

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/s/ David Peffer

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