MAY FILINGS

Comments on Comments on Apr 7 meeting

Initiative: Demand and distributed energy market integration

Comment period

Apr 09, 2025, 03:00 pm - May 01, 2025, 05:00 pm

Submitting organizations

Marin Clean Energy

Marin Clean Energy

Submitted on 05/01/2025, 02:54 pm

Contact

MCE Regulatory (regulatory@mcecleanenergy.org)

1. Please provide your organization’s comments on the Performance Evaluation Methodology (PEM) problem statements discussed during the April 7th Working Group. Do you agree the Working Group should move forward with trying to address the problem statement? Does the problem statement need further refinement?

1) The full suite of tariff approved methodologies is currently underutilized, leading to heavy centralization for using Day Matching Combined, which raises concerns on efficiency of the scale of options being offered and accuracy in performance evaluation options. 2) Existing PEMs, such as the commonly used 5-in-10 and 10-in-10 approaches, are either not well-suited for emerging DERs like behind-the-meter batteries and EVs, whose frequent dispatching distorts baseline calculations; or such as the MGO option, excludes the export of energy from behind-the-meter devices. 3) BTM device-level measurement is not recognized for use in developing baselines for PEM options. Performance evaluations depend on energy measurement (load and generation) and don’t recognize non-energy metered technologies contributions to load reduction calculation equivalents. 4) CAISO’s limited flexibility in adjusting details beyond its core baseline methodologies framework without tariff changes, restricts ability to keep pace with evolving market needs. 5) Requirement for registration of locations to be at the service account level prevents aggregators from developing resources at the customers device level 6) Requirement for control group end users to be registered in the Demand Response System limits use of non-participating end users within a control group and is in conflict with consumer data privacy rules

Marin Clean Energy (MCE) appreciates the opportunity to comment on the Performance Evaluation Methodology (PEM) problem statements discussed during the April 7th Working Group meeting. As discussed below, MCE recommends that the Demand and Distributed Energy Market Integration (DDEMI) Working Group:

Move forward with problem statements: one, two, and four;

Move forward with problem statement six, subject to revision to reflect other recognized challenges with the control group methodology; and

Not move forward with, or deprioritize, problem statements three and five at this time given their narrow focus on device-level measurement and registration.

MCE responses to individual problem statements are provided below:

1. The full suite of tariff approved methodologies is currently underutilized, leading to heavy centralization for using Day Matching Combined, which raises concerns on efficiency of the scale of options being offered and accuracy in performance evaluation options.

MCE agrees that tariff approved methodologies are currently underutilized. MCE supports the CAISO exploring the adoption of improvements to, and if necessary additional, PEMs. Reducing barriers for emerging Distributed Energy Resources (DERs) is critical for improving efficiency and accuracy, and for unlocking broader DER participation in CAISO markets. To the extent feasible, MCE encourages the CAISO to consider soliciting proposals for, and authorizing, pilot programs to test proposed enhancements or alternatives to methodologies before adopting changes to tariffs or Business Practice Manuals (BPMs).

2. Existing PEMs, such as the commonly used 5-in-10 and 10-in-10 approaches, are either not well-suited for emerging DERs like behind-the-meter batteries and EVs, whose frequent dispatching distorts baseline calculations; or such as the MGO option, excludes the export of energy from behind-the-meter devices.

MCE agrees that existing PEMs are in need of refinement to support emerging DER deployment and strategies. MCE supports CAISO exploring and adopting improvements to, and if necessary, additional PEMs. Reducing barriers for emerging DERs is critical for improving efficiency and accuracy, and for unlocking broader DER participation in CAISO markets. To the extent feasible, MCE encourages the CAISO to consider soliciting proposals for, and authorizing, pilot programs to test proposed enhancements or alternatives to methodologies before adopting changes to tariffs or BPMs.

3. BTM device-level measurement is not recognized for use in developing baselines for PEM options. Performance evaluations depend on energy measurement (load and generation) and don't recognize non-energy metered technologies contributions to load reduction calculation equivalents.

MCE does not support the Working Group moving forward with problem statements three and five at this time given the narrow focus on device-level measurement and registration. As a load-serving entity currently operating as a demand response provider, MCE does not see the current requirements as a barrier to scaling enrollment. However, a focus on the device-level approach could fracture the fundamental economic premise of DER aggregation at scale by introducing excessive complexity for the CAISO, market participants, and individual customers.

For example, moving to a device-level registration framework may lead to a lack of optimization at a single site, introducing confusion and the potential erosion of economic value of market participation, particularly at the account and individual customer level. If Asset 1 is being operated by one aggregator and Asset 2 is being operated by a different aggregator, and both assets are located at the same site, there could be a scenario where the assets work against each other. Device-level participation may also discourage the use of open-source communication protocols. In a site-level participation model, different devices must communicate with each other, or a central hub, to ensure co-optimization rather than rely on proprietary protocols. Account level participation ensures that all assets at an individual site are working together to achieve a specific objective.

A device-level framework would also require the CAISO to manage, verify, and maintain vast amounts of highly granular data, requiring significant administrative overhead and infrastructure that could increase barriers for participation and slow market growth. In contrast, the current account-level model offers a more practical balance between operational feasibility and costs, allowing for efficient aggregation while ensuring performance accountability.

Relatedly, during the April 7th meeting, the CAISO presented the following draft problem statements regarding demand response (DR) registration challenges: “DR registration is too complex, which limits DR participation or inaccurately reflects DR program capabilities; – DR participation in CAISO markets is constrained by reliance on utility meter data, cumbersome registration processes, and strict metering accuracy requirements that exclude many DERs; – While CAISO has PEM options for device-level performance measurement, current requirements—such as the IOU “click-through” registration process and ANSI C12 accuracy standards—undermine their accessibility and effectiveness.”

MCE agrees that DR participation in CAISO markets is currently limited by strict metering requirements, utility meter data processes, and high latency. MCE also agrees that timely access to utility meter data is a barrier to utilizing performance evaluation options other than Day Matching Combined. Rather than bypassing existing data sharing mechanisms — which already involve established processes and associated costs — priority should be placed on improving access to meter data and other scalable solutions that do not require the CAISO to directly manage individual devices. Efforts to enhance existing data sharing mechanisms are currently underway in California Public Utilities Commission (CPUC) proceedings. Accordingly, MCE would be in support of a problem statement that captures the performance evaluation barriers involving utility meter data, while recognizing and connecting to the improvement efforts active in other venues in place of problem statements three and five.

4. CAISO’s limited flexibility in adjusting details beyond its core baseline methodologies framework without tariff changes, restricts ability to keep pace with evolving market needs.

MCE agrees with this problem statement and recommends that the Working Group move forward with seeking additional flexibility in modifying existing methodologies without the need for Federal Energy Regulatory Committee (FERC) approved tariff changes. Specifically, MCE recommends that, to the extent reasonable and practicable, operational details be moved from the tariffs to the BPMs. Doing so will allow for the necessary flexibility to keep pace with evolving market needs as stakeholders expand their offerings and knowledge in this emerging space. If operational details are moved from the tariffs to BPMs, the CAISO should ensure that all stakeholders are aware of proposed changes and the stakeholder review process, by adopting a new stakeholder engagement process for changes to PEMs in the BPM.

5. Requirement for registration of locations to be at the service account level prevents aggregators from developing resources at the customers device level.

See response to problem statement three.

6. Requirement for control group end users to be registered in the Demand Response System limits use of non-participating end users within a control group and is in conflict with consumer data privacy rules.

MCE generally agrees that the Working Group should move forward with problem statement six, but suggests that the CAISO revise the current statement to reflect other recognized challenges with the control group methodology.

The control group methodology can yield more accurate outputs and reduce exogenous distortions to customer baseline calculations, but its use is constrained by current rules, including the requirement to register non-participant accounts for "matched" control groups.

MCE agrees that the Working Group should address the registration requirement discussed in problem statement six, but MCE would also highlight that this is not the only challenge with scaling the control group methodology. When the Working Group shifts to identifying proposed actions to address the developed problem statements. MCE encourages the CAISO to consider soliciting proposals for, and authorizing, pilot programs to test proposed enhancements or alternatives to the control group methodology before adopting any changes to tariffs or BPMs. This will ensure that there is time to test and learn from solutions in this early phase of DER adoption and market transformation.

2. Please provide any further comments related to the Performance Evaluation Methodology discussion from the April 7th Working Group discussion

In the April 7th meeting, MCE asked about the difference between a modification or enhancement to one of the three existing baseline types and the creation of a new methodology. MCE recommends that the CAISO provide clarification on any distinctions between the two and the associated paths forward as it relates to the Working Group's efforts for forming stakeholder recommendations for policy development. To this end, MCE recommends that the CAISO not preclude the adoption of any new PEMs.

MCE also supports those that have highlighted that the current accuracy standard is too prohibitive and recommends that the Working Group include a problem statement that would allow for amending the Metering BPM, and recommends the working group target a 1% accuracy requirement.

Attachments

[Comments on CAISO DDEMI April 7 Meeting -MCE.docx]

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 Through December 31, 2022 U 39 E	Application 23-02-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

PUBLIC VERSION

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: May 13, 2025

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

¥ Three separate rulings issued by three separate ALJs[1] in ERRA Compliance proceedings confirm: the reasonableness of an investor-owned utility's attempts to sell excess RA is relevant to and within the scope of an ERRA Compliance proceeding. ***!***

¥ The PD errs in analyzing the relevance of PG&E's attempts to sell excess RA to the scope of this proceeding. That question has already been conclusively resolved.***!***

¥ The PD's analysis of the relevance of PG&E's attempts to sell excess RA commits multiple legal and factual errors, and the Commission should not adopt it.***!***

¥ The PD does not meaningfully engage with the record evidence with respect to PG&E's attempts to sell excess RA during the summer of 2022, nor reach the merits of the parties' arguments with respect to that evidence.***!***

¥ The PD makes several technical errors that should be corrected in the Final Decision:

- o In several instances, the PD incorrectly states that CalCCA opposes or objects to the partial party settlement agreement between PG&E and Cal Advocates, and that CalCCA argues the settlement agreement should not be approved (at pages 2, 20, 27, 28, and Findings of Fact 3, 4 and 5). CalCCA did not and does not object to the settlement agreement, nor has CalCCA argued the settlement agreement should not be approved. Moreover, the settlement agreement did not purport to resolve the issues CalCCA raised in this proceeding. The PD should be corrected in each of those instances.

- o In multiple instances, the PD incorrectly states that the settlement agreement between PG&E and Cal Advocates resolved all issues in this proceeding (see pages 18, 27, Finding of Fact 2, Conclusion of Law 8). In fact, the settlement agreement resolved all issues raised by Cal Advocates in this proceeding, and the issues raised by CalCCA remain disputed.

- o At page 17, the PD incorrectly states that CalCCA contends that PG&E did not comply with Scoping Issue 5, citing to Exhibit CalCCA-01 at 1. CalCCA makes recommendations on matters relevant to Scoping Issues 1, 3 and 5, but does not contend that PG&E did not comply with Scoping Issue 5. The PD should be modified to correctly reflect CalCCA's position.

- o At page 17, the PD states: "CalCCA stated that because PG&E did not first make RA capacity available to Load Serving Entities (LSE)." (citations omitted). That sentence is incomplete as written. Further, it should be modified to correctly reflect CalCCA's position as follows: "CalCCA states that PG&E did not make reasonable attempts to

[1] Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this brief.

make its excess RA capacity available to other LSEs before counting that capacity towards its incremental system reliability procurement targets."

- o At pages 22-23, the PD states: "CalCCA contends that the Commission may review whether the utility maximized the value of its generation portfolio, which includes its RA resources, for the benefit of customers during the record period." The PD then finds that "CalCCA does not support its contention with any regulation, statute, or decisions." The PD is incorrect. While the sentence referenced by the PD comes from the introductory section to CalCCA's reply brief, and does not include a citation, CalCCA supports the same contention later in its reply brief with citations to multiple Commission decisions (*&' !*CalCCA Reply Brief at 3-4). The PD should be modified to correctly reflect CalCCA's argument.

- o At page 23, the PD states: "CalCCA contends that 'PG&E did not make reasonable attempts to sell excess RA capacity to other LSEs using the commercial process.'" (citations omitted) The PD's quote, which cites to CalCCA's opening brief, is incomplete. CalCCA contends: "PG&E did not make reasonable attempts to sell its excess RA capacity to other LSEs using the commercial processes described in its Bundled Procurement Plan." **'' !*CalCCA Opening Brief at 3.

¥ The Commission should scrutinize PG&E's assumptions about resource availability and the adjustments PG&E made to its System RA position in future ERRA Compliance proceedings to ensure any reductions to the excess RA capacity PG&E made available to the market are justified.

¥ The Commission should find PG&E did not make reasonable attempts to sell its excess RA capacity to other LSEs before counting that capacity towards its own system reliability incremental procurement targets.

¥ The Commission should not find that PG&E prudently managed its UOG and contracted facilities.

¥ The Commission should not find PG&E's entries recorded to the PABA are reasonable.

¥ The Commission should revisit PG&E's BPP in a separate rulemaking proceeding to ensure that PG&E is making its excess RA available to the market in a timely and comprehensive manner, including through scheduled solicitations and market offers outside the scheduled solicitation process.

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 Through December 31, 2022 U 39 E	Application 23-02-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these comments on Administrative Law Judge (ALJ) LeQuang's [Proposed]***!K' 42&#%1, , 0#- 2%L!)H !+<0)2<(!+<0)C *'))(' ? ' %)!1 L0' ' ? ' %)!M)N' ' %+<42@!A<&<%-!B(' 4)02!" #? , <%C<%-!)H !+$O(2!1 =- #4<)' &P @!' !*** [#] **!**(Proposed Decision or PD) in the above-captioned proceeding pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).

During the summer of 2022, while available capacity in the Resource Adequacy (RA) market was scarce and prices were high, Pacific Gas and Electric Company (PG&E) counted nearly a gigawatt of excess RA capacity towards its own incremental system reliability procurement targets instead of selling that capacity to other load-serving entities (LSE). Previous

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2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster 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.

3 !"#$%$&'()*+',-&-$.*/%%#$0-.1*23'*"4#2-45*"4#26*7'225'8'.2*/1#''8'.2*9'2:''.*"4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6*4.(*23'*"?@5-,*/(0$,42'&*A;;-,'B Application (A.) 23-02-018 (Apr. 23, 2025).

Commission decisions permit PG&E to use excess RA towards its procurement targets; however, PG&E must first make reasonable attempts to sell its excess capacity to other LSEs.[4]

PG&E's efforts (or lack thereof) to sell its excess RA to other LSEs directly impact community choice aggregators (CCA) and their customers for two reasons. First, PG&E's efforts bear directly on the Power Charge Indifference Adjustment (PCIA) rates that CCA customers pay. Sales proceeds from RA are credited to all PCIA ratepayers. If PG&E makes inadequate efforts to sell RA, that can result in CCA customers paying higher PCIA rates than they should be paying. Second, CCAs, like all LSEs, face RA program compliance obligations and must procure RA in the market to meet those obligations. PG&E's efforts to make its excess RA timely available, therefore, directly impact the ability of CCAs to procure sufficient RA capacity at reasonable prices.

Examining PG&E's efforts to sell RA is a critical part of the ERRA review of PG&E's portfolio management. CalCCA—which represents CCAs with RA compliance obligations and customers that pay charges which are impacted by PG&E's RA sales activities—must participate in ERRA Compliance proceedings in order to scrutinize PG&E's RA sales activities during the record period, among other issues. CalCCA does not seek to conduct a holistic reasonableness review of PG&E's RA sales volumes and prices in ERRA Compliance proceedings, as such a review is beyond the scope of these proceedings and would undermine the purpose of PG&E's sales framework (Appendix S of the Bundled Procurement Plan (BPP)). However, there is no other proceeding in which CalCCA can scrutinize PG&E's efforts to optimize its RA portfolio during the record year using solicitations and other commercial processes prescribed and permitted by its BPP.

The PD rightly acknowledges that "excess RA solicitations and market efforts are important issues that affect utilities, LSEs and ratepayers."[5] However, the PD goes on to slam the door shut on parties' ability to investigate PG&E's excess RA sales activities in ERRA Compliance proceedings, concluding "issues concerning PG&E's sales or attempts to sell excess

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4 Decision (D.) 21-12-015, "34&'*C*+',-&-$.*+-#',2-.1*"4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6B*7$?23'#.* >45-;$#.-4*=(-&$.*>$8%4.6*4.(*74.*+-'1$*<4&*D*=5',2#-,*>$8%4.6*2$*E4F'*/,2-$.&*2$*"#'%4#'*;$#* "$2'.2-45*=G2#'8'*H'423'#*-.*23'*7?88'#&*$;*CICC*4.(*CICJB Rulemaking (R.) 20-11-003 (Dec. 6, 2021) at 183-184 (permitting PG&E to count excess resources in its existing portfolios towards its incremental system reliability procurement targets "provided it has made reasonable attempts to sell this excess capacity to other LSEs").

5 PD at 25.

RA during the summer of 2022 are not relevant to determine whether PG&E complied with Scoping Memo Issues No. 1, 3 and 5."[6] The PD directs the "important issues" CalCCA has raised regarding PG&E's 2022 activities into a separate proceeding, noting that "an Order Instituting Rulemaking [(OIR)] relating to the ERRA and PCIA was approved by the Commission at the February 20, 2025 voting meeting, which contained references to possible consideration of these issues."[7]

The Commission should reject the PD based on multiple legal and factual errors. <u>First</u>, the PD's conclusion on relevance cannot be squared with at least three separate rulings by three separate Administrative Law Judges (ALJ) in ERRA Compliance proceedings, each of which find that a utility's attempts to sell excess RA are within the scope of ERRA Compliance proceedings. <u>Second</u>, the PD's relevance analysis errs where it fails to recognize that RA resources include utility-owned generation (UOG) and contracted resources, and therefore, a review of PG&E's prudent administration of those resources under Scoping Issue No. 1 must necessarily include consideration of PG&E's RA portfolio optimization. <u>Third</u>, the PD's relevance analysis on Scoping Issue Nos. 3 and 5 is illogical. On Scoping Issue No. 3, the PD simultaneously acknowledges the impact of PG&E's RA sales efforts on its recorded entries, while finding PG&E's efforts are not relevant to evaluating the appropriateness and accuracy of those entries—two conclusions that cannot be reconciled. On Scoping Issue No. 5, the PD concludes PG&E's excess RA sales efforts are not relevant to whether the utility administered RA sales consistent with its BPP, ignoring the glaring connection between the two: PG&E's BPP establishes the rules that guide PG&E's excess RA sales efforts.

Finally, while the PCIA OIR indeed contemplates the consideration of changes to PG&E's BPP as a part of Track Two, the scope of Track Two has not been finalized. While changes to the BPP must be and should be considered in that proceeding, CalCCA cannot conduct a backward-looking review of PG&E's 2022 RA sales efforts in the OIR. CalCCA must investigate those activities in this proceeding.

And in fact, CalCCA has done so. CalCCA issued substantial discovery regarding PG&E's 2022 RA sales activities, including several discovery requests issued following the ALJ's Ruling[8]

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7 K(. (referring to R.25-02-005).

8 A.23-02-018, /(8-.-&2#42-0'* L4:* M?(1'N&* O?5-.1* O'PA%'.-.1* +-&,$0'#6* ;$#* >45-;$#.-4* >$88?.-26*>3$-,'*/&&$,-42-$. (Jul. 26, 2024).

re-opening discovery for CalCCA to investigate this very issue. Several of PG&E's responses to CalCCA's discovery requests on this issue were admitted to the record as Exhibit CalCCA-04-C. Unfortunately, instead of closely evaluating the record and addressing the substantive merits of CalCCA's arguments, the PD focuses on reanimating the relevance of PG&E's excess RA sales efforts to ERRA Compliance proceedings. Had the PD considered the record evidence, it would have found PG&E did not make reasonable attempts to sell its excess RA to other LSEs before counting that capacity towards its own incremental system reliability procurement targets. Moreover, the PD would not have found that PG&E prudently managed its UOG and contracted resources, nor would it have found that PG&E's entries to the Portfolio Allocation Balancing Account (PABA) are reasonable.

The Commission should reject the PD's multiple factual and legal errors. The Commission should evaluate the record evidence with respect to PG&E's efforts to sell excess RA during the summer of 2022, and based on that evidence:

1. The Commission should scrutinize PG&E's assumptions about resource availability and the adjustments PG&E made to its System RA position in future ERRA Compliance proceedings to ensure any reductions to the excess RA capacity PG&E made available to the market are justified;
2. The Commission should find PG&E did not make reasonable attempts to sell its excess RA capacity to other LSEs before counting that capacity towards its own system reliability incremental procurement targets in 2022;
3. The Commission should not find that PG&E prudently managed its UOG and contracted facilities, and;
4. The Commission should not find PG&E's entries recorded to the PABA are reasonable.

Finally, the Commission should remedy a series of technical errors in the PD. The most significant of these errors was the PD's incorrect statements that CalCCA objected to, opposed, or argued against approval of, the partial party settlement agreement entered into by PG&E and Cal Advocates in this proceeding.

I.! THREE SEPARATE RULINGS CONFIRM PG&E'S EXCESS RA SALES ACTIVITIES ARE RELEVANT TO THE SCOPE OF THIS PROCEEDING

The PD makes scant reference to the record evidence concerning PG&E's attempts to sell excess RA during the record period and does not even reach the merits of the parties' arguments concerning that evidence. Instead, the PD resurrects the question of whether that evidence is

0'('-<%) to the scope of ERRA Compliance proceedings. The PD commits legal error because that evidentiary question has already been conclusively resolved, three separate times and by three separate ALJs.

First, the Scoping Memo in PG&E's pending 2024 ERRA Compliance proceeding includes the following scoping issue: "Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan, including whether PG&E made reasonable attempts to sell excess RA consistent with its Bundled Procurement Plan."[9] The 2024 Scoping Memo adopts CalCCA's recommendation to expressly include the reasonableness of PG&E's attempts to sell excess RA in scope,[10] over PG&E's objection[11] (which was based on the same relevance arguments PG&E raised in this proceeding). Thus, there can be no question that the reasonableness of PG&E's attempts to sell excess RA consistent with its BPP is relevant to the scope of ERRA Compliance proceedings.

Second, following extensive briefing in this proceeding,[12] the ALJ issued a Ruling in July 2024 re-opening discovery on "PG&E's attempts to sell excess existing, PCIA-eligible RA resources through the commercial processes of its Bundled Procurement Plan," among other

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9 A.25-02-013, /&&-1.'(*>$88-&&-$.'#N&*7,$%-.1*Q'8$*4.(*O?5-.1 (May 2, 2025) (2024 Scoping Memo), at 3 (emphasis added).

10 7'' A.25-02-013, >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&*"#$2'&2*2$*23'*/%%5-,42-$.*$;*"4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6 (Apr. 4, 2025), at 12-22.

11 7'' A.25-02-013, O'%56*$;*"4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6*RS*JT*=U*2$*"#$2'&2&B (Apr. 14, 2025), at 3-8.

12 7''*A.23-02-010,*Q$2-$.*2$*72#-F'*"$#2-$.&*$;*23'*"#'%4#'(*+-#',2*E'&2-8$.6*$;*9#-4.*73?'6*$.*9'345;*$;*23'*>45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.*@6*"4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6*RS*JTP=U (Oct. 6, 2023); >45-;$#.-4* >$88?.-26* >3$-,'* /&&$,-42-$.N&* O'&%$.&'* 2$* "4,-;-,* <4&* 4.(* =5',2#-,* >$8%4.6N&* Q$2-$.* 2$* 72#-F' (Oct. 23, 2023); "4,-;-,* <4&*4.(* =5',2#-,* >$8%4.6N&* RS* JTP=U* O'%56* K.* 7?%%$#2* A;* Q$2-$.*2$*72#-F'*"$#2-$.&*$;*23'*"#'%4#'(*+-#',2*E'&2-8$.6*$;*9#-4.*73?'6*A.*9'345;*A;*23'* >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$. (Nov. 2, 2023); >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&* Q$2-$.*2$*A;;'#*=G3-@-2&*K.2$*=0-('.,'*4.(*/(8-2*K.2$*23'*O',$#((Jan. 18, 2024); "4,-;-,*<4&*4.(*=5',2#-,* >$8%4.6N&*RS*JTP=U*Q$2-$.*K.*L-8-.'*2$*"#',5?('*V?'&2-$.-.1*$.*23'*745'*$;B*$#*/22'8%2&*E$*7'55*O'&$?#,'* /('W?4,6*A?2&-('*23'*7$5-,-242-$.&*O'W?-#'(*96*/%%'.(-G*7*$;*"<D=N&*9?.(5'(*"#$,?#'8'.2*"54.B*4.(* O'W?'&2*;$#*=G%'(-2'(*O?5-.1*42*23'*X'@#?4#6*YZB*CIC[*7242?&*>$.;'#'.,' (Feb. 14, 2024); >45-;$#.-4* >$88?.-26* >3$-,'* /&&$,-42-$.N&* Q$2-$.* ;$#* >$88-&&-$.* O'0-':* $;* /(8-.-&2#42-0'* L4:* M?(1'N&* =0-('.2-4#6*O?5-.1& (Feb. 23, 2024); "4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6N&*RS*JTP=U*O'&%$.&'*2$*23'*Q$2-$.* $;*23'*>45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.*;$#*>$88-&&-$.*O'0-':*$;*/(8-.-&2#42-0'*L4:*M?(1'N&* =0-('.2-4#6*O?5-.1&*(Mar. 11, 2024); >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&*O'%56*K.*7?%%$#2*A;* Q$2-$.*;$#*>$88-&&-$.*O'0-':*$;*/(8-.-&2#42-0'*L4:*M?(1'N&*=0-('.2-4#6*O?5-.1& (Mar. 21, 2024); >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&*9#-';*K.*O'&%$.&'*2$*/LMN&*Q46*CC*O?5-.1 (June 6, 2024); "4,-;-,*<4&*4.(*=5',2#-,*>$8%4.6N&*RS*JTP=U*9#-';*K.*O'&%$.&'*2$*/LMN&*Q46*CC*O?5-.1 (June 6, 2024).

issues.[13] If that issue were not relevant to the scope of this proceeding, there would have been no reason for the ALJ to expressly permit CalCCA to conduct further discovery on that issue. Again, there can be no question that the reasonableness of PG&E's attempts to sell excess RA consistent with its BPP is relevant to the scope of ERRA Compliance proceedings, including the instant proceeding.

Finally, an ALJ ruling in San Diego Gas & Electric Company's (SDG&E) 2022 ERRA Compliance proceeding further confirms the relevance of PG&E's excess RA sales activities to the scope of ERRA Compliance proceedings. In the SDG&E proceeding, certain parties sought a ruling compelling SDG&E to produce information fully responsive to data requests seeking to scrutinize SDG&E's attempts to maximize its RA sales during the record period.[14] The moving parties explained that during the summer of the record period, SDG&E relied on excess RA capacity from its existing resources to count toward its incremental system reliability procurement targets[15]—mirroring PG&E's treatment of excess RA during the summer of 2022. The moving parties asserted, therefore, that "[a]n important question for the Commission to consider in [SDG&E's 2022 ERRA compliance] proceeding is whether SDG&E should have offered more RA for sale in 2022 given this substantial excess RA capacity, ***2'.***, whether SDG&E prudently managed its portfolio during the record year that is the focus of this proceeding."[16] That question parallels the key disputed issue between CalCCA and PG&E in this proceeding: whether PG&E made reasonable attempts to sell its excess capacity to other LSEs during the summer of 2022 before transferring that capacity to CAM. The ALJ granted the motion over SDG&E's objection, finding SDG&E's responses to the data requests in question are "relevant to the scope of [SDG&E's ERRA Compliance] proceeding."[17]

Each of the above three rulings confirms that the utility's RA sales activities, and in particular, the reasonableness of its attempts to sell excess RA, are relevant to the scope of ERRA

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13 A.23-02-018, /(8-.-&2#42-0'* L4:* M?(1'N&* O?5-.1* O'PA%'.-.1* +-&,$0'#6* ;$#* >45-;$#.-4* >$88?.-26*>3$-,'*/&&$,-42-$. (Jul. 26, 2024).

14 A.23-06-002, Q$2-$.*2$*>$8%'5*+-&,$0'#6*$;*74.*+-'1$*>$88?.-26*"$:'#*4.(*>5'4.*=.'#16* /55-4.,' (Nov. 22, 2023).

15 K(. at 4-5.

16 K(. at 5.

17 A.23-06-002, =PQ4-5*O?5-.1*<#4.2-.1*74.*+-'1$*>$88?.-26*"$:'#*4.(*>5'4.*=.'#16*/55-4.,'* Q$2-$.*2$*>$8%'5*74.*+-'1$*<4&*D*=5',2#-,*>$8%4.6*2$*X?556*O'&%$.(*2$*74.*+-'1$*>$88?.-26*"$:'#* 4.(*>5'4.*=.'#16*/55-4.,'*+424*O'W?'&2&*@6**"]Q]*$.*+','8@'#*^B*CICJ (Dec. 4, 2023), at 2-3.

Compliance proceedings. The PD need not have analyzed that evidentiary question again, especially when the conclusions from that analysis are clearly wrong.

II.! THE PD'S RELEVANCE ANALYSIS COMMITS MULTIPLE LEGAL AND FACTUAL ERRORS

A.! PG&E's Attempts to Sell Excess RA During the Record Period are Relevant to Scoping Issues 1, 3, and 5

The three rulings discussed above leave no doubt that PG&E's attempts to sell excess RA during the record period are relevant to this proceeding. In fact, PG&E's attempts to sell excess RA during the record period are relevant to three separate scoping issues in this proceeding—Scoping Issues 1, 3, and 5. No reasonable person with an understanding of how the PCIA and PABA operate could conclude otherwise. CalCCA has submitted extensive briefing in this proceeding explaining why PG&E's attempts to sell excess RA are relevant to those three scoping issues[18] and therefore only briefly summarizes those arguments below.

PG&E's excess RA sales activities are relevant to Scoping Issue 1 because that issue requires the Commission to evaluate whether PG&E prudently administered and managed its generation portfolio (UOG and contracted resources) in the record year.[19] As a part of that broad evaluation, the Commission must assess whether PG&E administered and managed its RA resources prudently, which include UOG and contracted resources.[20] That prudence assessment, in turn, includes assessing whether PG&E made reasonable efforts to ensure it received value for all its RA resources, a key consideration in determining whether PG&E has prudently managed its generation portfolio.[21]

PG&E's excess RA sales activities are relevant to Scoping Issue 3 because those activities ultimately impact the entries PG&E made to its balancing accounts, including the PABA during the 2022 record period.[22] To be more specific, PG&E's attempts to sell its excess RA impact not

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18 7''* A.23-12-018, >45-;$#.-4* >$88?.-26* >3$-,'* /&&$,-42-$.N&* O'&%$.&'* 2$* "4,-;-,* <4&* 4.(* =5',2#-,*>$8%4.6N&*Q$2-$.*2$*72#-F' (Oct. 23, 2023); >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&*Q$2-$.* 2$*A;;'#*=G3-@-2&*K.2$*=0-('.,'*4.(*/(8-2*K.2$*23'*O',$#((Jan. 18, 2024); >45-;$#.-4*>$88?.-26*>3$-,'* /&&$,-42-$.N&*Q$2-$.*;$#*>$88-&&-$.*O'0-':*$;*/(8-.-&2#42-0'*L4:*M?(1'N&*=0-('.2-4#6*O?5-.1& (Feb. 23, 2024); >45-;$#.-4*>$88?.-26*>3$-,'*/&&$,-42-$.N&*O'%56*K.*7?%%$#2*A;*Q$2-$.*;$#*>$88-&&-$.*O'0-':*$;* /(8-.-&2#42-0'* L4:* M?(1'N&* =0-('.2-4#6* O?5-.1& (Mar. 21, 2024); >45-;$#.-4* >$88?.-26* >3$-,'* /&&$,-42-$.N&*9#-';*K.*O'&%$.&'*2$*/LMN&*Q46*CC*O?5-.1 (June 6, 2024).

19 A.23-02-018, >45-;$#.-4* >$88?.-26* >3$-,'* /&&$,-42-$.N&* Q$2-$.* ;$#* >$88-&&-$.* O'0-':* $;* /(8-.-&2#42-0'*L4:*M?(1'N&*=0-('.2-4#6*O?5-.1& (Feb. 23, 2024), at 15.

20 K(.

21 K(.

22 K(. at 19.

only the magnitude of PG&E's credit to PABA resulting from the transfer of excess RA to CAM, but also the actual amount of RA capacity PG&E sold during the record year.[23] Ultimately, PG&E's Actual Sold RA (compared to the amount of Sold RA it had forecasted it would sell) is a key factor driving whether an over- or under-collection exists in the PABA, which in turn drives the revenue requirement for the following year's PCIA rates that PG&E's customers pay.[24] The facts of PG&E's attempts to sell excess RA during the summer of 2022 therefore go to whether PG&E's PABA entries are "reasonable, appropriate, accurate, and in compliance with Commission decisions."[25] Put differently, should the Commission find PG&E's attempts to sell its excess RA capacity were ***%#)!***reasonable, and could have resulted in a different PABA balance at the end of 2022 due to increased sales of RA, it might determine PG&E's PABA entries were not "reasonable, appropriate, accurate and in compliance with Commission decisions."[26]

Finally, the facts of PG&E's excess RA sales activities are relevant to Scoping Issue 5 because those facts go to whether PG&E conducted RA sales consistent with Appendix S of its BPP.[27] Those facts include PG&E's RA positions; the calculation of its RA positions; the timing of PG&E's calculation of its RA position; the timing and outcomes of its RA solicitations; and PG&E's attempts to sell its excess RA capacity using the commercial processes in Appendix S of its BPP.[28]

B.! The PD's Analysis of the Relevance of PG&E's RA Sales Activities to Scoping Issues 1, 3, and 5 Commits Multiple Legal and Factual Errors and is Illogical

The PD's relevance analysis not only conflicts with three separate rulings in ERRA Compliance proceedings, but it also commits multiple legal and factual errors and is illogical.

With respect to Scoping Issue 1, the PD states: "Issue No. 1 on its face does not mention RA in any way" and "[a] plain language review of Issue No. 1 reveals that it specifically relates to UOG, QFs and non-QFs."[29] The PD fails to recognize, however, that PG&E's RA resources ***2%4($=' !***both UOG and contracted resources—in other words, those are the very resources that

23 K(]
24 K(. at 19-20.
25 K(. at 20.
26 K(.
27 * K(. at 22.
28 K(.
29 PD at 23.

provide RA.[30] The following table details the RA provided in 2022 (MW available and MW used for compliance) from PG&E's portfolio as well as its PCIA portfolio:[31]

		2022 RA Available (MW)	2022 RA Used for Compliance
PG&E Portfolio	Contracts	[redacted]	[redacted]
	UOG	[redacted]	[redacted]
		[redacted]	[redacted]
PG&E PCIA Portfolio	Contracts	[redacted]	[redacted]
	UOG	[redacted]	[redacted]

Indeed, if UOG and contracted resources do not provide RA, as the PD suggests, what resources are left to provide capacity? The fact Scoping Issue 1 does not specifically reference "RA" is immaterial because it references PG&E's prudent administration management of its UOG and contracted resources—in other words: its generation portfolio, which includes the RA provided by those resources.

With respect to Scoping Issue 3, the PD contradicts itself, leading to an illogical conclusion. In one instance, the PD acknowledges the relevance of PG&E's attempts to sell excess RA to Scoping Issue 3, where it states: "the transfer from PABA to CAM does impact PG&E's entries recorded[.]"[32] Later in its discussion, however, the PD concludes PG&E's sales or attempts to sell excess RA during the summer of 2022 are not relevant to determine whether PG&E complied with Scoping Issue 3.[33] Those two conclusions cannot be reconciled because PG&E's sales or attempts to sell excess RA directly impact the magnitude of its transfer from PABA to CAM—which, as the PD acknowledges, impacts PG&E's recorded entries. There can be no question that under D.19-10-001 sales of RA impact the PABA. Thus, PG&E's sales or attempts to sell excess RA are *necessarily* relevant to Scoping Issue 3.

Finally, with respect to Scoping Issue 5, the PD notes that CalCCA does not challenge PG&E's compliance with Appendix S of its BPP.[34] But the PD leaps from that premise to the conclusion that PG&E's sales or attempts to sell excess RA are not relevant to determine whether

30 *See, e.g.,* Ex. PGE-01 at 3-18 (discussing how the Elkhorn BESS, a UOG facility, provided both System and Flex RA capacity during the record year).

31 PG&E response to CalCCA Master Data Request 1.08, Attachment 1.

32 PD at 23.

33 *Id.* at 25.

34 *Id.* at 24.

PG&E complied with Scoping Issue 5.[35] The PD does not offer any reasoning for that leap, and its conclusion again defies logic. Scoping Issue 5 asks whether PG&E administered RA sales consistent with its BPP; the BPP defines and describes commercial processes for the sale of RA; and CalCCA seeks to review PG&E's use of those commercial processes to sell its excess RA. Nothing in the PD explain why that review is <u>not relevant</u> to Scoping Issue 5, notwithstanding PG&E's compliance or lack of compliance with its sales framework.

In light of the multiple legal, factual, and logical errors in the PD's relevance analysis, the Commission should, therefore, decline to adopt that analysis in its entirety and evaluate the record evidence and parties' arguments on their merits.

C.! The PD Violates Due Process Requirements by Denying CalCCA an Opportunity to Address PG&E's Excess RA Sales at a Meaningful Time and in a Meaningful Manner.

The Commission is bound by constitutional due process requirements.[36] Due process requires that parties be given adequate notice and opportunity to be heard.[37] Failure to afford parties adequate due process is grounds for reversal of a Commission decision.[38] With respect to the "opportunity to be heard" element of due process, the key is that parties have an opportunity to participate at a meaningful time and in a meaningful manner.[39]

Here, if the PD's conclusions with respect to the relevance of CalCCA's arguments were adopted, it would effectively deny parties a meaningful opportunity to address PG&E's attempts to sell excess RA beyond the solicitations required by its BPP in 2022. That is because, as CalCCA's brief in response to the ALJ's May 22 Ruling explains in detail, this ERRA Compliance proceeding is the <u>only opportunity</u> for affected parties to scrutinize PG&E's efforts to sell excess RA in 2022 and determine whether those efforts meet the relevant legal standards.[40] The Commission therefore should not adopt the PD's relevance analysis, and preserve the parties

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35 K(. at 25.

36 "'$%5'*0]*H'&2'#.*/-#5-.'&*K.,]*(1954) 42 Cal.2d 621, and*O4-5#$4(*>$8 8-&&-$.*$;*>45-;$#.-4*0]* "4,-;-,*<4&*4.(*=5',2#-,*>$8%4.y (1938) 302 U.S..

37 "'$%5'*0]*H'&2'#.*/-#*L-.'&B*K.,] (1954) 52 Cal.2d at 632.

38 7'' Cal. Pub. Util. Code § 1757.1(a)(6).

39 7''*']1]B O64.*0]*>45-;$#.-4*K.2'#&,3$54&2-,*X'('#42-$.P74.*+-'1$*7',2-$. (2001) 94 Cal.App.4th 1048, 1071-1072.

40 7''*California Community Choice Association's Brief in Response to ALJ's May 22 Ruling at 18-22 (Jun. 6, 2024).

opportunity to address PG&E's attempts to sell its excess RA in this ERRA Compliance proceeding.

III.! WHILE THE COMMISSION SHOULD CONSIDER CHANGES TO THE BPP IN THE PCIA OIR, THAT CONSIDERATION DOES NOT SUBSTITUTE FOR AN ERRA REVIEW OF PG&E'S RECORD YEAR PORTFOLIO MANAGEMENT

Despite its several errors, the PD correctly observes that "excess RA solicitations and market efforts and important issues that affect utilities, LSEs, and ratepayers."[41] The PD states the Commission "will take CalCCA's proposal to revisit PG&E's BPP and Appendix S proceeding under advisement" and nods to the PCIA OIR (R.25-02-005), which references the possible consideration of the BPP as a Track Two issue.

The Commission should consider changes to PG&E's BPP in Track Two of the OIR. However, that consideration should not and cannot substitute for a thorough review of PG&E's record year RA portfolio management, including its attempts to sell excess RA to other LSEs, in this proceeding. That backward-looking review can only happen in the ERRA Compliance proceeding, and the Commission should not prevent parties from conducting that review in future ERRA Compliance proceedings, notwithstanding the scope of the PCIA OIR or any other rulemaking in which the Commission considers the IOUs' RA sales practices.

IV.! THE PD DOES NOT MEANINGFULLY ENGAGE WITH THE RECORD EVIDENCE REGARDING PG&E'S ATTEMPTS TO SELL EXCESS RA

As a threshold matter, the PD appears to operate under the misapprehension that the partial settlement agreement entered into by PG&E and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) (Settlement Agreement) purports to resolve all issues in this proceeding. It does not. The Settlement Agreement clearly states that it "resolve[s] all issues <u>raised by Cal Advocates</u>" in this proceeding.[42] While CalCCA did not oppose the Settlement Agreement—another fact the PD gets wrong[43]—the Settlement Agreement expressly ***=#' &%#)!*** address CalCCA's issues in this proceeding, which remain disputed.[44]

With respect to those disputed issues, the PD nominally finds "CalCCA has failed to demonstrate that PG&E did not comply with its obligations within Scoping Memo Issue Nos. 1, 3

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41 PD at 25.
42 Settlement Agreement at 1 (emphasis added).
43 These comments will address the PD's technical errors below.
44 Settlement Agreement at 1.

and 5."[45] But the PD's discussion focuses exclusively on the relevance analysis—it does not meaningfully engage with the record evidence or reach the merits of CalCCA's arguments. CalCCA submitted extensive direct testimony (Ex. CalCCA-01-C), an excerpted portion of PG&E's BPP (Ex. CalCCA-02 and Ex. CalCCA-03-C), and several PG&E responses to CalCCA discovery requests (Ex. CalCCA-04-C) in support of its arguments regarding PG&E's excess RA sales during the summer of 2022. The PD does not discuss or analyze any of CalCCA's evidence where it assesses whether: 1) PG&E prudently administered its RA portfolio; 2) PG&E made the appropriate account entries; or 3) PG&E conducted RA sales consistent with Appendix S of its BPP. The PD makes only a passing reference to Exhibit CalCCA-04-C as the evidence CalCCA submits to "support its contention", but in a footnote to that sentence, cites only to a single subpart of a single discovery response within CalCCA's exhibit (PG&E confidential response to CalCCA Data Request 3.31a). That reference is an extraordinarily cursory and misleading summary of the evidence CalCCA submitted in support of its contentions in this proceeding. The Commission should revise the PD and carefully analyze the record evidence with respect to PG&E's attempts to sell its excess RA during the summer of 2022, else the Decision will be subject to reversal on appeal for failing to support its decision with findings, and its findings with substantial evidence.[46]

Had the PD analyzed the record evidence, it would have found that PG&E did not make reasonable attempts to sell its excess RA to other LSEs in 2022 before counting that RA towards its incremental system reliability procurement targets. PG&E states it identified the final quantity of excess RA capacity shown towards meeting Summer Reliability procurement targets between T-50 and T-30 days prior to each compliance month.[47] That means PG&E did not identify the final quantity of excess RA capacity counted towards meeting incremental procurement targets for July, August, and September 2022 until <@ 0!its Q3 Balance of Year Solicitation (for which PG&E prepared an RA Position on April 11, 2022). Similarly, that timeline means PG&E did not identify the final quantity of excess RA capacity counted towards PG&E's incremental procurement target for October 2022 until <@ 0!the Q4 Balance of Year Solicitation (for which PG&E prepared an RA position on July 18, 2022).

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45 PD at 25.

46 Cal. Pub. Util. Code § 1757.

47 CalCCA-04C, PG&E response to CalCCA data request 3.26, 3.33.

[redacted][48] In fact, in 2022, [redacted][49]

Yet, [redacted] In fact, [redacted] Instead, PG&E counted hundreds of megawatts towards its own system reliability incremental procurement targets [redacted] Far from making "reasonable attempts" to sell the excess RA it identified, therefore, PG&E [redacted]

V. THE PD MAKES SEVERAL TECHNICAL ERRORS, INCLUDING THE INCORRECT STATEMENT THAT CALCCA OPPOSED THE SETTLEMENT AGREEMENT

The PD makes several technical errors that should be corrected in the Commission's Decision. Most significantly, the PD states in multiple instances that CalCCA opposed the partial settlement agreement, which is incorrect—CalCCA did not oppose the partial Settlement Agreement, as the Joint Motion for Adoption of Settlement Agreement clearly indicates.[52] Specifically, the Commission should correct the following technical errors:

- In several instances, the PD incorrectly states that CalCCA opposes or objects to the partial party settlement agreement between PG&E and Cal Advocates, and that CalCCA argues the settlement agreement should not be approved (at pages 2, 20, 27, 28, and Findings of Fact 3, 4 and 5). CalCCA did not and does not object to the settlement agreement, nor has CalCCA argued the settlement agreement should not

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48 CalCCA-04C, PG&E response to CalCCA data request 7.01; CalCCA-03C at 13.

49 CalCCA-04C, PG&E response to CalCCA data request 7.02, 7.03.

50 CalCCA-04C, PG&E response to CalCCA data request 7.05c, 7.06c, 7.07c, 7.08c [redacted]

51 CalCCA-04C, PG&E response to CalCCA data request 7.05d, 7.06d, 7.07d, 7.08d [redacted]

52 Joint Motion of Pacific Gas and Electric Company (U 39 E) and the Public Advocates Office at the California Public Utilities Commission for Adoption of the Settlement Agreement, A.23-02-018 (Mar. 7, 2024), at 2 (stating "CalCCA confirmed it had no objection to the Settling Parties' proposed settlement").

be approved. Moreover, the settlement agreement did not purport to resolve the issues CalCCA raised in this proceeding. The PD should be corrected in each of those instances.

¥ In multiple instances, the PD incorrectly states that the settlement agreement between PG&E and Cal Advocates resolved all issues in this proceeding (see pages 18, 27, Finding of Fact 2, Conclusion of Law 8). In fact, the settlement agreement resolved all issues raised by Cal Advocates in this proceeding, and the issues raised by CalCCA remain disputed.

¥ At page 17, the PD incorrectly states that CalCCA contends that PG&E did not comply with Scoping Issue 5, citing to Exhibit CalCCA-01 at 1. CalCCA makes recommendations on matters relevant to Scoping Issues 1, 3 and 5, but does not contend that PG&E did not comply with Scoping Issue 5. The PD should be modified to correctly reflect CalCCA's position.

¥ At page 17, the PD states: "CalCCA stated that because PG&E did not first make RA capacity available to Load Serving Entities (LSE)." (citations omitted). That sentence is incomplete as written. Further, it should be modified to correctly reflect CalCCA's position as follows: "CalCCA states that PG&E did not make reasonable attempts to make its excess RA capacity available to other LSEs before counting that capacity towards its incremental system reliability procurement targets."

¥ At pages 22-23, the PD states: "CalCCA contends that the Commission may review whether the utility maximized the value of its generation portfolio, which includes its RA resources, for the benefit of customers during the record period." The PD then finds that "CalCCA does not support its contention with any regulation, statute, or decisions." The PD is incorrect. While the sentence referenced by the PD comes from the introductory section to CalCCA's reply brief, and does not include a citation, CalCCA supports the same contention later in its reply brief with citations to multiple Commission decisions (*&' !*CalCCA Reply Brief at 3-4). The PD should be modified to correctly reflect CalCCA's argument.

¥ At page 23, the PD states: "CalCCA contends that 'PG&E did not make reasonable attempts to sell excess RA capacity to other LSEs using the commercial process.'" (citations omitted) The PD's quote, which cites to CalCCA's opening brief, is incomplete. CalCCA contends: "PG&E did not make reasonable attempts to sell its excess RA capacity to other LSEs using the commercial processes described in its Bundled Procurement Plan." *'' !CalCCA Opening Brief at 3.

VI.! CONCLUSION

For the reasons described in these comments, CalCCA respectfully urges the Commission to adopt the changes discussed herein and presented in Appendix A, and to grant any other relief the Commission deems just and reasonable.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: May 13, 2025

APPENDIX

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CalCCA provides this Appendix setting forth proposed changes to the ***V+0#, #&=!K' 42&#%M1 , , 0#-2%L!)H !+<0)2<(! +<0)C*'))(' ? ' %)!1 L0' ' ? ' %)!M)N' ' %+<42@4!A <&<%=!B(' 4)024!" #? , <%C<%=!)H !+$O(24!1 =-#4<)' & P@4'***, including proposed changes to the findings of fact, conclusions of law and ordering paragraphs. CalCCA's proposed revisions appear in underline and strike-through.

Findings of Fact

[. . .]

2. On March 7, 2024, Settling Parties filed a Joint Motion for approval of the Settlement Agreement that resolves ~~all disputes~~ <u>issues raised by Cal Advocates</u> regarding PG&E's ERRA Compliance.

3. ~~CalCCA opposed the Joint Motion and the Settlement Agreement.~~

4. ~~Issues raised by CalCCA in opposition to the Settlement Agreement regarding PG&E's sales or attempts to sell RA during the summer of 2022 are outside the scope of this proceeding.~~

5. Issues raised by CalCCA ~~in opposition to the Settlement Agreement~~ regarding PG&Es' sales or attempts to sell RA during the summer of 2022 are <u>within the scope of this proceeding, but broader issues concerning PG&E's RA sales framework are</u> ripe for consideration in another Commission proceeding.

[. . .]

14. PG&E has <u>not</u> prudently administered and dispatched its UOG resources and portfolio of contracts, QFs, non-QFs, renewable energy resources, in compliance with PG&E Commission-approved BPP.

15. The entries and costs recorded in the ERRA and other accounts contained herein are appropriately and correctly stated<u>, with the exception of the PABA, which may be incorrectly stated due to PG&E's failure to make reasonable attempt to sell its excess RA to other LSEs prior to counting that capacity towards its own incremental system reliability procurement targets</u>.

[. . .]

Conclusions of Law

[. . .]

7. CalCCA ~~failed to~~ demonstrate<u>d</u> that PG&E did not fulfill its obligations under Scoping Memo Issue Nos. 1~~,~~ <u>and</u> 3 ~~and 5~~. ~~All of CalCCA's protests have been resolved.~~

8. With all contested issues raised by Cal Advocates being resolved by the Settling Parties, and all other contested issues being resolved by this Decision, it is in the public interest for the Commission to close this proceeding.

9. The Commission should approve PG&E's compliance ERRA application for Record Year 2022, consistent with the terms set forth in the Settlement Agreement and in this Decision.

X. PG&E did not make reasonable attempts to sell its excess RA to other LSEs before counting that capacity towards its own system reliability incremental procurement targets.

Ordering Paragraphs

[. . .]

2. The Application of Pacific Gas and Electric Company (PG&E), Application 23-02-018, is approved consistent with the terms set forth in the Settlement Agreement between PG&E and the Public Advocates Office at the Public Utilities Commission, and with this Decision.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON ORDER INSTITUTING RULEMAKING

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May 19, 2025

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

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON ORDER INSTITUTING RULEMAKING

I. Introduction and Background

Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Marin Clean Energy ("MCE"), respectfully submits these Opening Comments on the *Order Instituting Rulemaking* ("OIR" or "PD") issued on April 29, 2025. MCE thanks the Commission for its longstanding and continuously evolving leadership on effective energy efficiency ("EE") programs. MCE supports the proposed scope and schedule for the oversight of EE portfolios, policies, programs and evaluation with minor recommendations. MCE finds the proposed scope of policy and implementation issues comprehensively provides a clear direction to ensure beneficial oversight of EE portfolios. EE portfolio programs remain essential to advancing California's clean energy and reliability goals in an affordable and equitable manner. MCE specifically supports:

- The proposed preliminary structure of the EE oversight proceeding into policy issues and implementation issues.

- Scoping natural gas policy issues and viable electric alternatives to gas measures in the context of broader state decarbonization issues.
- Scoping the elect-to-administer community choice aggregator budget formula.
- Scoping policy guidance for the 2026 portfolio applications.
- Scoping portfolio guidance and cost-effectiveness.
- Scoping the treatment of multifamily buildings and programs.
- Scoping the potential and goals study.
- Scoping oversight of the 2024-2027 portfolios.

MCE recommends the Commission clarify its proposed scope on "Community Choice Aggregator ("CCA") Oversight,"[1] and explicitly scope integrated demand side management ("IDSM") programs guidance for 2024-2027 portfolios. MCE further requests the Commission prioritize scheduling and decisions on the potential and goals study and policy guidance for the 2026 portfolio applications. Portfolio administrators must have the necessary time to synthesize, plan and incorporate any changes from the potential and goals study and any policy guidance for the 2026 portfolio applications prior to their submission in quarter one of 2026.[2]

MCE is a CCA who provides clean electricity service and clean energy programs to 38 member communities across Contra Costa, Marin, Napa, and Solano counties. Since 2013, MCE has administered energy efficiency programs under California Public Utilities Code Section 381.1(a)-(d). MCE currently administers EE programs for the 2024-2027 program years ("PY") as an apply-to-administer program administrator ("PA"). Pursuant to Decision ("D.") 21-05-031,

[1] EE Oversight OIR at p. 4.
[2] Portfolio administrators submitted 2024-2027 EE Applications in quarter one of 2022. MCE submitted its 2024-2027 EE Application on March 04, 2022. A.22-03-012.

MCE filed its *Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan* ("MCE EE Application") with the Commission pursuant to Article 2 of its Rules of Practice and Procedure, California Public Utilities Code § 381.1 and D. 21-05-031 on March 04, 2022. On July 3rd, 2023, the Commission issued D.23-06-055 approving MCE's EE Application.[3]

MCE administers a diverse suite of EE programs in the resource acquisition, market support and equity segments that serve residential, commercial, agricultural, public, industrial and equity customers. MCE's experience as a PA of EE portfolio programs and its connections to the 38 communities it serves informs its comments on the proposed scope and schedule for this proceeding.

II. MCE Comments on Preliminary Scope of R.25-04-010

a. MCE Recommends the Commission Clarify Its Preliminary Scoping of CCA Elect-to-Administer Budget Formula and Policy Issues

MCE recognizes and supports the diverse portfolio administration pathways available to CCAs.[4] CCAs may act as apply-to-administer CCAs, elect-to-administer CCAs, and as administrators of regional energy networks ("RENs"). Presently, CCAs administer EE programs as apply-to-administer portfolio administrators, elect-to-administer portfolio administrators and RENs.[5] MCE, as stated above, administers EE programs under the apply-to-administer pathway.

MCE supports the Commission scoping oversight of CCA elect-to-administer budget formulas.[6] MCE reads the Commission's scoping of CCA oversight issues to mean elect-to-

[3] *See* D.23-06-055 at pp. 93, 103 (approving MCE's portfolio budget and Application programs).
[4] California Public Utilities Code Section 381.1(a)-(d); D.19-12-021.
[5] EE Oversight OIR at p. 12 (respondents).
[6] EE Oversight OIR at p. 4.

administer CCA budget formula oversight issues as evidenced by its description in the proposed proceeding schedule: "CCA Elect-to-Administer Budgets and Policy[.]"[7] To avoid confusion with other potential policy issues related to alternative CCA administration pathways, MCE recommends the Commission clarify its scoping of "Community Choice Aggregator Oversight"[8] is limited to elect-to-administer budget formula policy issues.

b. MCE Recommends the Commission Scope IDSM Programs Guidance for 2024-2027

MCE requests the Commission explicitly scope IDSM program guidance for the current 2024-2027 portfolios. In the prior EE Application proceeding, the Commission issued D.23-06-055 allowing PAs to expend a percentage of their 2024-2027 EE portfolio budgets[9] on IDSM programs that deliver "ongoing load shifting that reduces peak consumption."[10] The Commission required PAs to submit Tier 3 advice letters with program details by March 15, 2024.[11] MCE and several PAs submitted advice letters with proposed IDSM programs and frameworks on March 15, 2024.[12]

As of the date of this filing, the Commission has not adopted a resolution approving the proposed IDSM programs and frameworks for PY 2024-2027. Even after a draft resolution moves through the Commission's required public comment and adoption process,[13] PAs will require time to refine and launch program proposals. This leaves little time within the approved 2024-2027 PYs to administer budget authorized IDSM programs. Additional guidance is

[7] EE Oversight OIR at p. 10.
[8] EE Oversight OIR at p. 4.
[9] D. 23-06-055 at p. 79 ("for programs to be launched during the portfolio period (2024-2027)[.]"
[10] D.23-06-055 at p. 78.
[11] *Id*. at p. 79.
[12] *See* MCE AL 74-E.
[13] CPUC Rules of Practice and Procedure 14.5.

required from the CPUC on the administration of these IDSM programs given the profound timing constraints.

c. MCE Recommends the Commission Prioritize Scheduling Decisions on the Potential and Goals Study and Guidance for the 2026 Portfolio Applications

MCE requests the Commission schedule decisions on the potential and goals study and guidance for the 2026 Portfolio Applications as soon as possible. MCE appreciates the Commission proposing decisions for both areas in quarter 3 of 2025.[14] However, MCE reiterates the urgent need for both decisions to allow for timely submissions of 2026 portfolio applications in 2026 and to ensure continuity of programs in PYs 2028-2031. The potential and goals study determines the statewide goals for EE and thus must be finalized prior to a PA's preparation of its portfolio applications that advance progress on said goals. Similarly, any 2026 portfolio application guidance must be issued with sufficient time for PAs, parties, and stakeholders to review and incorporate it into their subsequent 2026 portfolio applications and comments.

Designing compliant proposals and preparing the required documents requires many teams, staff members, administrative resources and significant stakeholder outreach and community engagement. Based on its experiences preparing and submitting the *2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan*, MCE estimates 10 months is an adequate timeline for application preparation and submission.[15] Following the submission of portfolio applications, the public, parties, and Commission staff need adequate time to review, engage with and comment on submissions prior to any final decisions. During the last portfolio application cycle, PAs submitted applications in March 2022,

[14] EE Oversight OIR at pp. 9-10.
[15] Following final Commission guidance and EE Application template.

and the Commission issued a final Decision in July 2023 constituting a 16-month engagement and review timeline.[16] To support timely submissions of 2026 portfolio applications and the continuity of portfolio programs through 2028-2031, MCE requests urgent prioritization of scheduling decisions on the potential and goals study and 2026 portfolio application guidance.

III. Categorization of Proceeding and Need for Hearings

MCE supports the Commission's preliminary determination categorizing the EE oversight proceeding as a ratesetting proceeding and thereby limiting *ex parte* communications. MCE agrees the proposed scope of the proceeding will likely impact ratepayer costs and savings. MCE does not presently anticipate disputed facts or see the need for evidentiary hearings. However, MCE does not object to the preliminary determination that evidentiary hearings may be necessary. MCE reminds the Commission that the schedule of this proceeding must be sensitive to and align with the 2028-2031 EE portfolio application preparation and submission schedule. MCE requests the Commission balance any requests that impact the schedule of the EE oversight proceeding with the 2028-2031 EE portfolio application schedule.

IV. Confirmation of Party Status

Pursuant to Rule 1.4(d) of the CPUC's Rules of Practice and Procedure, MCE confirms its party status, and participation in this proceeding. MCE is an apply-to-administer EE portfolio administrator and a named respondent to this OIR.[17]

MCE submits its party representative:

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[16] *See* D.23-06-055 at pp. 3-5.
[17] EE Oversight OIR at p. 12.

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V. Conclusion

MCE thanks the Commission and Energy Division staff for their ongoing commitment to effective, affordable, reliable and equitable EE portfolios and for the opportunity to submit comments. MCE looks forward to collaborating with the Commission, program administrators, parties, and stakeholders to continue refining and evolving California's leading EE programs.[18]

Dated: May 19, 2025.

Respectfully submitted,

/s/ Wade Stano
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[18] American Council for an Energy-Efficient Economy, 2025 State Energy Efficiency Scorecard, available at: https://www.aceee.org/sites/default/files/pdfs/the_2025_state_scorecard.pdf (ranking California the top state for energy efficiency programs in the United States for the 7th time) at p. 11.

Comments on 5/13 call

Initiative: Demand and distributed energy market integration

Comment period

May 13, 2025, 03:00 pm - May 27, 2025, 05:00 pm

Submitting organizations

Marin Clean Energy

Marin Clean Energy

Submitted on 05/27/2025, 01:58 pm

Contact

MCE Regulatory (regulatory@mcecleanenergy.org)

1. What baseline improvements would increase performance, entry, and demand flexibility innovation?

Marin Clean Energy (MCE) appreciates the opportunity to comment on the questions presented by the Department of Market Monitoring during the May 13th Demand and Distributed Energy Market Integration (DDEMI) Working Group meeting. As discussed in MCE's response to question two, the following improvements to the control group method would increase performance, entry, and demand flexibility innovation:

- Removing or modifying the requirement to register non-participant end users for load-serving entities (LSEs) with existing access to non-participant data;
- Facilitating use of standardized load profile data sets for control group formation;
- Addressing other prohibitive barriers such as requiring 20 pre-event days and the use of a new control group for each event; and
- Allowing for limited and data-based adjustments to control group baselines to account for known differences between the control and treatment group.

Streamlining an LSEs' use of its customer data or enabling use of standardized load profiles for control group formation would significantly reduce computational barriers, lower costs for market entrants, and accelerate scaled deployment of innovative demand flexibility programs.

Additionally, MCE encourages the CAISO to consider soliciting proposals for, and authorizing, pilot programs to test alternative baseline approaches to the control group methodology. Pilots could be implemented in the near term by continuing to settle on an existing approved performance evaluation methodology (PEM) while simultaneously evaluating performance using alternative baseline techniques. MCE is currently developing an alternative baseline method and encourages the CAISO to authorize a pilot program that would allow for testing MCE's alternative baseline in settlement. MCE's approach is being designed to enable daily signal participation and enhance the performance value by rewarding more frequent load-shifting, and is further discussed below.

2. Why are the control group and weather matching baselines not widely used?

MCE has no comment on the weather matching baseline at this time, nor can MCE speak to why the baselines are not widely used by market participants at-large. Rather, MCE's comments are focused on the barriers that MCE has encountered in employing the control group method.

MCE's primary barrier with the control group method is captured in performance evaluation methodology (PEM) problem statement six, which states that the "[r]equirement for control group end users to be registered in the Demand Response System limits use of non-participating end users within a control group and is in conflict with consumer data privacy rules."[1] The requirement to register non-participant end users for use in control group analysis significantly slows and complicates the process. MCE believes this likely contributes to overall low utilization of the control group method despite its known advantages.[2] To register a non-participant end user, the user must "opt-in" to having their data used in the Demand Response Registration System (DRRS). This is an inhibitory and unnecessary step.

As the user won't be participating in or benefiting from the demand response (DR) program, there is no reason or incentive for them to opt-in. Further, as an LSE, MCE already has access to the requisite non-participant customer data – data which MCE already uses in CAISO settlements. Removing the registration or opt-in requirement for LSEs with existing access to non-participant data would lead to increased utilization of the control group method.

MCE recognizes that the CAISO needs to otherwise verify the customer exists and is not registered in another DR program. MCE encourages exploration of other mechanisms to conduct those verifications, such as by exploring the solutions offered by PG&E in their comments on the April 7th DDEMI working group meeting. MCE also recognizes that access to non-participant data for third-party demand response providers (non-LSEs) is an issue, but MCE believes this is outside the scope of the DDEMI working group and is currently being addressed at the California Public Utilities Commission.[3]

The registration requirement also forces a program to be designed in one of two ways. The first would be to create an internal control group by sending no signals to a group of participants. However, this decreases the value of program participation and decreases the value of the program as a whole. The other option would be to conduct the costly and arduous process of registering enough non-participant end users in the DRRS to create a pool of control group participants that is sufficiently larger than your participant group. Once enough control group participants are registered, next there are significant and costly computational requirements to validate and settle on the control group method. It requires significant resources to store all the data used for control group formation and all the calculation logs for generating baseline performance and comparison to the treatment group.

MCE agrees with the premise behind the prescriptive baseline concept proposed by Leap.[4] Access to statewide, standardized load profile data sets[5] for control group formation would both circumvent the registration issue and reduce the computational power required to utilize the control group method. However, unlike Leap's proposal for state-level baseline development, MCE believes that the state should create standardized state-level load profiles, but that demand response providers (DRPs) should maintain the ability to calculate the baseline for their DR programs.

MCE encourages the working group to move forward with problem statement six, but notes that the non-participant registration issue is not the only challenge with scaling the control group method. Additional barriers faced with this method include the requirement to create a new control group for each event, the requirement for 20 pre-event days, and the inability to adjust the baseline to account for pre-existing differences between the control and treatment group.

Requiring the formation of new control groups for each event is inefficient and further increases the costs and computational power required to implement the control group method. Currently, each control site can only be used in a single control group. Thus, the pool of potential control sites for each subsequent participant is reduced until the pool is eventually exhausted. MCE is currently working on developing a modified methodology, which in part evaluates how many control groups a site may be used in before it begins to create impactful bias. The requirement for 20 pre-event days further limits utilization of the control group method because it limits use of sites that receive daily signals. MCE's modified methodology uses Bayesian statistical methods to create evolving baselines that require less non-participation performance data. This methodology trains an existing baseline with new information, rather than creating one from scratch for each event, and is designed to use intermittent non-participation days to update an evolving baseline.

Lastly, there is currently no way for a DRP to modify the baseline to account for pre-existing differences between the control and treatment group. Allowing for limited and data-based adjustments to control group baselines to account for known differences would further reduce the cost and computational power required to utilize the control group method.

[1] *Demand and Distributed Energy Market Integration (DDEMI) Working Group (WG) Presentation*, California ISO, May 13, 2025:
https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Demand-Distributed-Energy-M

arket-Integration-May-13-2025.pdf

[2] See *Demand Response Advanced Measurement: Methodology Analysis of Open-Source Baseline and Comparison Group Methods to Enable CAISO Demand Response Resource Performance Evaluation*, Recurve Analytics, Inc., February, 2022: https://www.caiso.com/Documents/Demand-Response_Advanced_Measurement_Methodology_updated_Feb_2022.pdf

[3] See California Public Utilities Commission (CPUC) Data Working Group established under R. 22-11-013, *Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards*: https://www.laregionalcollaborative.com/data-working-group/

[4] *DDEMI WG Presentation - Prescriptive Baselines in CAISO*, Leap, March 3, 2025: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Leap-Prescriptive-Baselines-Mar-03-2025.pdf

[5] Similar to the Systemwide Dynamic Load Profiles that community choice aggregation programs use for billing determinants, for example.

Attachments

MCE 5_13 DDEMI Stakeholder Comment Template.docx

May 28, 2025

Via Electronic Mail

Energy Division
Attention: Tariff Unit
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Via E-Mail: EDTariffUnit@cpuc.ca.gov

Re: Joint Community Choice Aggregators' Comments on Draft Resolution E-5367

Dear Energy Division Tariff Unit:

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission") and the notice accompanying Draft Resolution E-5367, Ava Community Energy, Clean Power Alliance of Southern California, the City and County of San Francisco, acting by and through its Public Utilities Commission, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, San Diego Community Power, San Jacinto Power, and San José Clean Energy (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") submit these comments on Draft Resolution E-5367, *Approving with Modifications Pacific Gas & Electric Company's and Southern California Edison Company's DAC-GT Cost Containment Cap Proposal Update*, to be considered at the June 12, 2025 Commission meeting ("Draft Resolution").

The Draft Resolution, as written, inhibits the ability of program administrators ("PAs") to successfully procure under the Disadvantaged Communities Green Tariff ("DAC-GT") program. The proposed cost containment framework is built on unsupported assumptions, employs a multiplier that is inadequate under current and foreseeable market conditions, and neglects to establish a process to timely resolve the proposal's likely failures. If adopted without significant revision, the Resolution will render the DAC-GT program unworkable for many PAs, particularly Community Choice Aggregator ("CCA") PAs, and will undermine the Commission's statutory objective of expanding clean energy access in disadvantaged communities ("DACs"). These comments identify material, factual, and technical errors in the Draft Resolution and propose targeted corrections to ensure the program can be successfully implemented across all service territories. The Joint CCAs offer necessary revisions in these comments that balance the success of future DAC-GT solicitations, the advancement of economic and environmental benefits for low-income customers in DACs, and customer affordability more broadly.

BACKGROUND

On May 30, 2024, the Commission adopted Decision ("D.") 24-05-065, which ordered Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") (collectively, the "Joint IOUs") to work with participating CCAs to develop a proposal for updating the cost containment cap applicable to the DAC-GT program.[1] The Commission further ordered PG&E and SCE to submit a Tier 2 Advice Letter proposing an updated methodology for the cost containment cap that reflects the option for pairing storage.[2]

The DAC-GT program, initially authorized by D.18-06-027 and implemented via Resolution E-4999, provides eligible residential customers in DACs with 100 percent renewable electricity at a 20 percent bill discount. To limit non-participating ratepayer subsidization, Resolution E-4999 also established a numeric cost containment cap threshold. The cost containment cap was originally set at 200 percent of the highest executed contract price in either the most recent Renewable Auction Mechanism's ("RAM") as-available peaking category, or the previous Green Tariff, whichever was higher.[3]

Pursuant to D.24-05-065, the Joint IOUs filed Joint Advice Letter SCE 5362-E and PG&E 7363-E on August 28, 2024, outlining a proposed methodology for updating the DAC-GT cost containment cap. The Joint IOUs held two meetings with the Joint CCAs, on July 18 and July 24, 2024, and corresponded via email to facilitate development of the proposal. The Joint IOUs' proposal identified two components of the updated cost containment cap methodology: (1) a Confidential Benchmark Value Reference Price ("CBVRP"), calculated as the average price of historical executed Power Purchase Agreements ("PPAs") for similar technologies and contract types over a defined time period, and (2) a DAC Percentage Multiplier ("Multiplier"), intended to account for cost differences specific to DAC-GT projects. Under this structure, the final cost containment cap is equal to the product of the CBVRP and the Multiplier.[4]

While the Joint IOUs and Joint CCAs generally agreed that there should be two cost containment cap elements, they proposed different implementation details, including the appropriate Multiplier and whether CBVRPs should be unique to each PA or uniform across the state. In turn, the Joint IOUs filed public and confidential versions of the advice letter. The public version provided a general outline of the proposed methodology and implementation details. Confidential Appendices A and B contain the Joint IOUs' characterization of the Joint CCAs' proposal and the Joint IOUs' confidential critiques, respectively. San Diego Gas &

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[1] D.24-05-065, Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program, issued June 7, 2024, at p.133.
[2] *Id.* at p. 171 (Ordering Paragraph ("OP") 4).
[3] Commission Resolution E-4999, Pursuant to Decision 18-06-027, Approving with Modification, Tariffs to Implement the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs, at p. 66 (OP 1.dd).
[4] Joint Advice Letter SCE AL 5362-E and PG&E AL 7363-E, Cost Containment Cap Proposal Update for Disadvantaged Communities Green Tariff Pursuant to Decision 24-05-065, Submitted August 28, 2024, at p. 3.

Electric Company ("SDG&E") did not submit a corresponding advice letter due to its Commission-authorized termination of its DAC-GT program, reflecting its uniquely small, bundled service customer base.

On September 17, 2024, the Joint CCAs, the Coalition for Community Solar Access ("CCSA"), the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), and the Solar Energy Industries Association ("SEIA") submitted protests to the Joint Advice Letter. The Joint IOUs replied to the protests and submitted a Joint Supplemental Advice Letter with expanded justification for confidentiality designations and an updated summary of the Joint CCAs' proposals.[5] Within their Joint Supplemental Advice Letter, the Joint IOUs also argued that the PAs should perform their own CBVRP analyses and submit them to independent evaluators for review.

The Joint CCAs submitted a protest to the Joint Supplemental Advice Letter on November 26, 2024, providing additional justifications regarding the confidentiality of the Joint IOUs' filings, the inadequacy of the proposed Multiplier, and the failure to provide a meaningful statewide methodology for calculating the CBVRP. On December 5, 2024, the Joint IOUs filed their reply defending their confidentiality designations, rejecting the proposed 175 percent Multiplier, and maintaining that PA-specific CBVRPs better reflect locational and contractual variation.

On May 8, 2025, the Commission issued Draft Resolution E-5367 which proposes to adopt the Joint IOUs' Advice Letter with modifications. As set forth below, the Joint CCAs submit these comments to identify material, factual, and technical errors in the Draft Resolution's support of the Joint IOUs' cost containment cap proposal. As detailed in the sections that follow, the proposed cost containment framework is unworkable due to its reliance on insufficient and non-comparable executed contract data, an inadequately low multiplier, and the absence of a contingency process to address foreseeable procurement failures. Adoption of the Draft Resolution in its current form would result in an outcome that is neither just nor reasonable and is inconsistent with the applicable Commission standards.

COMMENTS

I. The Proposed CBVRP Methodology is Unworkable

The Draft Resolution's proposed cost containment cap framework is structurally unsound and fails to address the realities of DAC-GT implementation. First, it relies on a methodology that presumes all PAs, including CCAs, have access to a sufficient pool of executed, comparable PPAs. This assumption is not supported by the record and does not reflect the reality of CCA DAC-GT procurement. Second, the Draft Resolution defines "comparable" contracts too narrowly, focusing on resource and contract type while omitting critical cost drivers like project

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[5] Joint Advice Letter SCE 5362-E-A and PG&E 7363-E-A, Supplement to 5362-E et al., Cost Containment Cap Proposal Update for Disadvantaged Communities Green Tariff Pursuant to Decision 24-05-065, Submitted November 6, 2024.

size. Third, the fallback option of allowing CCAs to adopt IOU-developed CBVRPs is not a reasonable substitute. IOU procurement portfolios often differ significantly in size and scope, leading to distorted cost containment caps that CCAs cannot reasonably procure under. Finally, the framework fails to incorporate a viable offramp for situations where a bid fails to produce adequate solicitations. To correct this, the Commission should authorize the use of a neutral third-party entity to pool anonymized contract data from multiple PAs to generate regionally appropriate CBVRPs. Without these changes, the adopted cost containment cap will not reflect actual market conditions or program constraints, and the DAC-GT program will be unworkable for many PAs.

a. The Draft Resolution Incorrectly Assumes that All Program Administrators Have Sufficient Executed PPAs to Calculate an Effective CBVRP

The Draft Resolution proposes a CBVRP methodology that requires each PA to calculate its CBVRP by surveying its executed contracts and "pooling prices from a comparable set of competitively solicited power purchase agreements... the entity executed...."[6] The PPAs are to be drawn from a pool of contracts (1) for similar resources, (2) for similar contract types, and (3) that have been executed within the last five years.[7] These CBVRPs are then to be reviewed by an Independent Evaluator for reasonableness.[8]

The proposed CBVRP methodology rests on a factual error in presuming that all DAC-GT PAs have, or each IOU has, a sufficient set of executed, comparable competitively solicited PPAs that satisfy the Draft Resolution's criteria. Many of the Joint CCAs do not have a sufficient history of executed contracts from which to survey to set their own CBVRP that meets the requirements and standards proposed in OP 2, or which reflect current market prices and developer costs.[9] As a result, the CCAs with few or no executed DAC-GT PPAs may need to rely on surveying executed contracts that do not reflect DAC-GT market conditions or developer costs to calculate their CBVRP.[10]

While CCAs have the option to survey non-DAC-GT PPAs, these contracts are often for larger-scale projects and may result in a cost containment cap that does not account for costs associated with developing projects that meet DAC-GT requirements. Alternatively, CCAs may need to use the CBVRP set by their respective IOU as proposed in the Draft Resolution.[11]

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[6] Draft Commission Resolution E-5367. Pursuant to Decision 24-05-065, Approving with Modifications Pacific Gas & Electric Company's and Southern California Edison Company's DAC-GT Cost Containment Cap Proposal Update, May 8, 2025, at p. 18 (OP 2).
[7] *Id.* at p. 13.
[8] Ibid.
[9] D.24-05-065, at p. 162 (Findings of Fact 78).
[10] While Community Solar Green Tariff ("CSGT") projects should be considered comparable and similar, only one CCA continues to offer a CSGT program. In turn, for purposes of these comments, "DAC-GT PPAs" will encompass executed CSGT PPAs.
[11] Draft Resolution E-5367, at p. 13.

However, the IOU may also have limited or no history of comparable executed contracts. The Joint CCAs address the proposal for CCAs to leverage the CBVRP set by the IOU for their service territory later in these comments.

In surveying CCA-executed non-DAC-GT PPAs, CCAs will likely need to review contracts that ultimately skew towards resources that exceed the maximum DAC-GT system size of 20 megawatts ("MW"). On a per MW basis, non-DAC-GT PPAs that exceed 20 MW tend to result in lower contract prices than DAC-GT PPAs, at least due to economies of scale. Surveying those PPAs will result in a cost containment cap that is undervalued for the DAC-GT program, which would not reflect market conditions or developer costs since DAC-GT PPAs historically have resulted in projects that do not exceed 3MW.[12]

b. The Draft Resolution's Definition of "Comparable" PPAs Is Technically Incomplete and Risks Skewing Cost Containment Caps

The Draft Resolution defines "comparable" PPAs based on similar resource type, similar contract type, and whether the contract has been executed within the last five years, but fails to incorporate project size as a critical metric.[13] DAC-GT projects must be sized between 500 kW and 20 MW and interconnected at the circuit, load or substation level. To date, projects executed through the DAC-GT program have not exceeded 10MW, and when excluding PG&E, have not exceeded 3MW.[14] These specifications result in pricing structures that differ significantly from large, utility-scale projects. The Draft Resolution errs in including executed contracts for projects significantly larger than the DAC-GT program size cap in the CBVRP calculation, as they will further skew the CBVRP downward, making the cost containment cap unworkable for a successful program. As such, the Joint CCAs urge the Commission to expand the guidance on what constitutes a "comparable" project to projects sized between 500 kW and 20 MW to ensure objectivity and consistency in the reasonableness review.

c. IOU CBVRPs Do Not Function as a Reasonable Proxy for CCAs with Insufficient Data

To accommodate CCAs with insufficient comparable contract history, the Draft Resolution allows CCA PAs to adopt the CBVRP set by the IOU for the relevant service territory.[15] This proposed system presents a significant technical error: IOU-calculated CBVRPs

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[12] *See* R.14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering, DAC-GT PA's First Quarter 2025 DAC-GT Quarterly Reports submitted by April 30, 2025.
[13] Draft Resolution E-5367, at p. 13.
[14] D.18-06-027, Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities, issued June 22, 2018, at p. 103 (OP 11) and *see* p. 51.
[15] Draft Resolution E-5367 at p. 18 (OP 2).

are not reasonably comparable or applicable for most CCAs due to differences in program size, procurement scale, and resource expectations. For example, five CCA PAs have a remaining DAC-GT capacity allocation under 4MW, significantly limiting the size of eligible projects and making their programs structurally different from the IOUs.[16] Further, it is unclear whether each of the IOUs will have sufficient comparable executed PPAs when excluding non-DAC-GT PPAs for projects that exceed 20MW that would otherwise skew the CBVRP downward. Even within those bounds, available IOU data may not represent the range of project sizes eligible under the DAC-GT program and result in a CBVRP that effectively excludes projects that more accurately represent bids expected to be received through the program based on the history of the DAC-GT program to date. As such, a determination of whether the data pool of IOU PPAs is sufficient should consider whether there is a reasonable representation of project sizes. Moreover, for CCAs using the CBVRP set by the IOU, it is critical that the CCA PA be provided the opportunity to review the IOU's methodology and be able to comment and/or protest if necessary.

d. The Commission Should Direct a Neutral Third Party to Pool Comparable PPA Data for Regional or LSE-Specific CBVRPs

For CCAs without sufficient historical data, and where IOU CBVRPs are not appropriate, the Commission should select and authorize a neutral third-party entity to pool anonymized pricing data from a comparable set of competitively solicited PPAs executed by participating DAC-GT PAs that satisfy the CBVRP categorical requirements. The third party would then develop a CBVRP for individual CCA PAs as needed based on comparable projects within a given geographic proximity.

As an example, the third-party entity could pool executed PPA data for a CCA PA based on a regional geographic boundary or once a sufficient number of data points, as determined by the third party, is reached. This approach would mitigate the risks of data insufficiency or data that is not representative of expected project bids and ensure that cost containment caps reflect actual market trends and comparable project characteristics. This third-party structure would improve consistency, transparency, and efficiency while respecting the confidentiality of underlying contracts. Moreover, utilizing a single third-party entity for all CCA PAs using this approach would be a more prudent use of ratepayer funds as opposed to each PA contracting with a third party.

II. The 120% Multiplier is Likely Too Low to Receive Viable Project Bids and Should be Increased to 140%

In addition to the issues associated with the CBVRP, the Draft Resolution's proposed 120% Multiplier does not adequately account for actual market conditions and above-market costs beyond project siting. The Draft Resolution supports the 120% Multiplier primarily on the basis that expanding the DAC-GT siting eligibility to include locations within five miles of a DAC "should reduce developers' costs."[17] While some limited cost savings may result from this

[16] D. 24-05-065, at pp. 138-139.
[17] Draft Resolution E-5367, at p. 14.

geographic expansion, the Draft Resolution treats siting as the sole or primary driver of project costs for distributed projects of this scale. This reasoning ignores a wide array of other factors that materially affect project costs and does not justify an 80% reduction in the Multiplier.

Notably, the Draft Resolution fails to consider external economic pressures that are likely to increase project costs in the near term, such as the impacts of impending tariffs and the potential termination or reduction of the Investment Tax Credit ("ITC"). The ITC is a longstanding federal tax credit incentive for solar development, in place since 2006 and scheduled to step down to 0% by 2036.[18] Since 2006, the ITC has had, and continues to have, a significant impact on reducing the costs of solar development and driving the growth of solar. Currently, Congress is considering repealing or reforming the ITC, with proposals ranging from accelerating the existing ITC phaseout schedule to terminating the ITC in the near-term. The uncertainty of the future of the ITC in addition to the uncertainties of potential tariffs on the solar market could result in significant increases in costs. These potential near-term cost impacts have not been taken into consideration in the Draft Resolution. By dismissing these material economic pressures and focusing narrowly on siting costs, the Draft Resolution risks understating the multiplier required to attract viable project bids.

The Draft Resolution also errs in referencing the bid price cap adopted for the Enhanced Community Renewables ("ECR") program as a justification for selecting the 120% Multiplier.[19] The 120% Multiplier was adopted for unrestricted ECR projects, which lacked the size, location, and participant restrictions applicable to DAC-GT projects. In contrast, the ECR Environmental Justice ("EJ") Reservation category, which shares many of the characteristics of the DAC-GT program, including restrictions on siting and customer eligibility criteria, was authorized with a 200% multiplier.[20] The Draft Resolution fails to explain why the more analogous ECR EJ category is not the appropriate point of comparison.[21]

Finally, D.24-05-065 discontinued future procurement under ECR due to the program's shortcomings. This limited participation and ultimate discontinuance underscores that a 120% cap was not effective for projects serving disadvantaged communities and should not be used as a benchmark for the DAC-GT program, which is designed to benefit those very communities.

In the Draft Resolution, the Commission declined to set the multiplier at 175%, citing concerns that such a level may not reflect current market conditions and could negatively impact

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[18] *See* U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Federal Solar Tax Credits for Businesses, February 2024.

[19] Draft Resolution E-5367, at p. 15.

[20] D.15-01-051, Decision Approving Green Tariff Shared Renewables Program for San Digo Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company Pursuant to Senate Bill 43, Issued February 2, 2015, at p. 10.

[21] *See* D.15-01-051, at pp. 4-5. Capacity for the ECR EJ category was reserved for facilities no larger than 1 MW "located in areas previously identified by the California Environmental Protection Agency... as the most impacted and disadvantaged communities... as the most impacted and disadvantaged communities."

non-participant affordability by increasing the overall DAC-GT program subsidy.[22] Unfortunately, the proposed 120% Multiplier in the Draft Resolution does not reflect market conditions particularly for investments in or near DACs, and will likely not result in viable project bids. The proposed Multiplier also does not account for the foreseeable near-term market changes mentioned above. This is particularly concerning considering PA's CBVRPs under the methodology proposed in the Draft Resolution are likely to underestimate DAC-GT market conditions and developer costs as previously discussed.

The Joint CCAs recommend the Commission adopt a reasonable increase in the Multiplier to 140%. A 140% Multiplier would improve the likelihood of successful bids by equipping PAs to better navigate the challenges with the proposed cost containment cap methodology and accommodate potential rapid and near-term market changes while mitigating the Commission's concerns around a higher cost containment cap as raised in the Draft Resolution.

a. The Final Resolution Must Include a Built-In Contingency Process

As discussed above, the Draft Resolution's proposed adoption of the Joint IOU's CBVRP and implementation of a 120% Multiplier will likely result in cost containment caps that are too low to support viable DAC-GT project development. As such, it is critical that the Final Resolution include a contingency process to address the possible scenario where a PA receives zero conforming bids at or below the cost containment cap that also meet all program requirements as established by the Commission. PAs must have access to a well-defined procedural pathway to update the cost containment cap in the instance that it proves to be infeasible.

To address this, the Joint CCAs recommend that the Commission incorporate in the Final Resolution a contingency option for each PA to propose and justify an adjustment to their cost containment cap multiplier via an Advice Letter submittal when zero conforming bids are received (1) at or below the cost containment cap and (2) otherwise meet all program requirements as established by the Commission. The PA's proposed adjusted cost containment cap multiplier must be substantiated by a PA's solicitation results and must not exceed 175% of the CBVRP. In the PA's Advice Letter filing, subject to confidential protection of market sensitive data, the PA would summarize the results of their solicitation, including the number of bids received, the percentage of bids that exceeded the cost containment cap, and if the bids would have fulfilled program requirements. Pending the Commission's review of the PA's Advice Letter submittal, the PA may adjust the multiplier for its cost containment cap. This process would preserve Commission oversight while providing necessary flexibility for PAs to adapt to evolving market conditions, including the aforementioned ITC and tariffs.

[22] Draft Resolution E-5347, at p. 13.

CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments.

Respectfully,

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Service List: A.22-05-022, R.14-07-002

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON ORDER INSTITUTING RULEMAKING

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May 29, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON ORDER INSTITUTING RULEMAKING

I. Introduction

Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Marin Clean Energy ("MCE"), respectfully submits these Reply Comments on the *Order Instituting Rulemaking* ("OIR") issued on April 29, 2025.[1] MCE offers support for additional proposed scoping topics from parties including the California Energy Efficiency Coordinating Committee ("CAEECC"),[2] the *Environmental and Social Justice Action Plan* ("ESJ"),[3] reconsideration of the Market Support and Equity segments 30 percent budget cap,[4] and the consideration of energy affordability, participant measure costs[5] and non-energy benefits ("NEBs") within the scope of cost-effectiveness (2.1.4.2). [6] MCE further notes agreement among parties on the need for integrated demand side management ("IDSM") programs guidance for program years ("PY") 2024-2027[7] and timely resolution of proposed scope issues on "Policy Guidance for 2026 Portfolio Applications[.]"[8] MCE finally recommends the Commission

[1] Opening comments submitted by parties on May 19th, 2025.
[2] NRDC OIR Opening Comments, p. 1; Willdan OIR Opening Comments, p. 3.
[3] Joint REN OIR Opening Comments, pp. 23-24.
[4] PG&E OIR Opening Comments, p. 10.
[5] CEDMC OIR Opening Comments, p. 3; SCE OIR Opening Comments, pp. 4-5.
[6] EE Oversight OIR, p. 6.
[7] *See e.g.* Joint REN OIR Opening Comments, pp. 25-26; CEDMC OIR Opening Comments, pp. 4-5.
[8] EE Oversight OIR at p. 4; Joint REN OIR Opening Comments, p. 9; PG&E OIR Opening Comments p. 2.

include low-global warming potential ("low-GWP") refrigerants into its energy efficiency oversight scope.[9]

II. MCE Reply Comments on Preliminary Scope of R.25-04-010

a. *MCE Supports the Commission Scoping California Energy Efficiency Coordinating Committee*

MCE agrees with the Natural Resources Defense Council ("NRDC") that adding CAEECC to the proposed scope will provide the Commission with beneficial flexibility to, if deemed appropriate, make relevant updates or clarifications on its role and responsibilities.[10] As the Commission refines the policies and procedures supporting energy efficiency ("EE") programs more broadly in this proceeding, it's prudent to permit exploration of how CAEECC may continue to support stakeholder involvement and the evolution of EE programs.

b. *MCE Supports the Commission Scoping the Environmental and Social Justice Action Plan*

MCE supports the Joint Regional Energy Network ("Joint REN") recommendation to scope the ESJ Action Plan into this proceeding.[11] The ESJ Action Plan is an essential document designed to promote both procedural justice[12] within Commission proceedings and distributive justice[13] in the form of improved outcomes for ESJ communities and households. MCE finds the ESJ Action Plan is a helpful tool to achieve the goal of this proceeding to set EE policies[14] and is inextricably tied to many issues already identified in the proposed scope.

c. *MCE Supports the Commission Scoping Reconsideration of the Market Support and Equity Segments 30 Percent Budget Cap*

MCE supports Pacific Gas & Electric's ("PG&E") recommendation to include reconsideration of the Market Support and Equity segments 30 percent budget cap in the proposed scope within the 2026 Portfolio Application Guidance.[15] MCE agrees with PG&E as fellow EE

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[9] Senate Bill 1013 (Lara, 2018).
[10] NRDC OIR Opening Comments, p. 1.
[11] Joint REN OIR Opening Comments, pp. 23-24.
[12] ESJ Action Plan Vol. 2.0. pp. 4-6 (e.g. Goal 1; Goal 5).
[13] *Id*. (e.g. Goal 2; Goal 4; Goal 7).
[14] EE Oversight OIR, p. 2.
[15] PG&E OIR Opening Comments p. 10.

apply-to-administer program administrator ("PA") that the existing 30 percent Market Support and Equity segments budget cap place significant barriers to investing in equity programs that deliver meaningful affordability benefits to low-income customers and to advancing the state's decarbonization goals.

Presently, the 30 percent budget cap without a minimum funding floor for Equity segment programs unnecessarily discourages meaningful investments in programs that enhance low-income customers' energy affordability. MCE understands and supports the Commission's commitment to cost-effective EE programs,[16] however the need for EE programs to directly improve the well-being of low-income customers impacted by the energy affordability crisis has grown since the 2021 adoption of this budget cap.[17] As the *2024 Senate Bill 695 Report* states, "Given multiple cost pressures that are causing rates to rise, it is imperative that we make strategic investments[.]"[18] The Commission should reconsider this budget cap in light of the energy affordability crisis[19] and evaluate if adjustments to this cap may better advance California's important affordability and decarbonization goals.

d. MCE Supports the Commission Scoping the Consideration of Energy Affordability, Participant Measure Costs and Non-Energy Benefits within Cost-Effectiveness (2.1.4.2)

MCE agrees with several parties requesting consideration of energy affordability, participant measure costs and NEBs in the Commission's proposed scoping of cost-effectiveness.[20] As discussed in MCE's Opening Comments on the EE Oversight OIR, MCE supports a modern and thoughtful discussion of cost-effectiveness as proposed by the Commission.[21] As the Commission explains, "As part of a process of continual improvement of energy efficiency programs, adjustments may be needed to cost-effectiveness policies and their

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[16] MCE OIR Opening Comments, p. 2.
[17] CPUC, 2024 Senate Bill 695 Report, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf, p. 3.
[18] *Id.*
[19] Executive Order N-5-24.
[20] SCE OIR Opening Comments, pp. 4-5; SoCalREN OIR Opening Comments, pp. 2-3; Joint REN Comments, p. 19; CEDMC OIR Opening Comments, p. 5.
[21] MCE OIR Opening Comments, p. 2.

application within energy efficiency portfolios and programs."[22] MCE agrees improved cost-effectiveness analysis can support improved EE programs in greater alignment with the Commission and state's various related policy goals. As many parties persuasively explain, the Commission's current cost-effectiveness analysis may improve by adding explicit consideration of and prioritization of improved affordability outcomes.[23]

MCE supports parties' recommendations to include a discussion of the removal of participants' measure costs in cost-effectiveness calculations.[24] Including measure costs paid for by private customer investment distorts the Commission's rightful focus on overseeing the effectiveness and performance of EE ratepayer funds. Including participant measure costs also illogically discourages voluntary private customer investment which can help allow deeper direct install projects with transformative equipment that provide greater energy savings, improved energy affordability, and NEBs to participating customers.

MCE further agrees with party comments that cost-effectiveness analysis and portfolio evaluation generally may benefit from a greater exploration of NEBs.[25] Greater exploration of NEBs allows the Commission to more comprehensively evaluate the true performance and benefits of EE programs. This information is vital to continue improving and refining EE programs' performance in alignment with the state's climate and affordability goals. MCE recommends including a discussion on energy affordability, participant measure costs and NEBs in the Commission's scoped discussion of cost-effectiveness.

e. MCE Supports the Commission Scoping Low-GWP Refrigerants

The proposed scoping excludes discussion of low-GWP refrigerants. MCE requests the Commission include discussion of low-GWP refrigerants. Senate Bill 1018 requires, "The Public Utilities Commission shall consider developing a strategy for including low-GWP refrigerants in equipment funded by the energy efficiency programs overseen by the Public Utilities Commission."[26] Consistent with *Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency*, MCE remains committed to exploring programs and measures that support the

[22] EE Oversight OIR, p. 6.
[23] *See e.g.* SCE OIR Opening Comments pp. 4-5; Joint REN OIR Opening Comments, pp. 17-18.
[24] CEDMC OIR Opening Comments, p. 3; SCE OIR Opening Comments, pp. 4-5.
[25] SoCalREN OIR Opening Comments, pp. 2-3; CEDMC OIR Opening Comments, pp. 5-6.
[26] Senate Bill 1013 (Lara, 2018) sec. 76002.

use of and transition to low-GWP refrigerants.[27] The *Forward-Looking Low-Global Warming Potential Refrigerant Transition Study – Draft Report*[28] released in June 2024 offers several policy recommendations to better support the state's transition to low-GWP refrigerants through EE programs. MCE finds these recommendations and this topic ripe for review by the Commission in concert with its Policy Guidance for 2026 Portfolio Application Guidance.[29]

III. Conclusion

MCE thanks the Commission for the opportunity to submit reply comments on the proposed scope of this proceeding. MCE respectfully requests the Commission update the proposed scope to include these key additions to accelerate the continued evolution of California's robust and beneficial EE programs.

Dated: May 29, 2025. Respectfully submitted,

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[27] MCE EE Application, p. 16.
[28] CPUC, DNV, GROUP A Forward-Looking Low-Global Warming Potential Refrigerant Transition Study – Draft Report, June 2024, available at: https://pda.energydataweb.com/#!/documents/3983/view, pp.8-10.
[29] EE Oversight OIR, p. 4.

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

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING REQUIREMENTS OF SENATE BILL 1142 AND EXTREME HEAT DISCONNECTIONS PROTECTIONS

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May 29, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA respectfully recommends that the Commission:

- Approve the Proposed Decision's reconnection framework as it strikes a balance between protecting customers and addressing customer arrearages;
- Approve the Proposed Decision's reconnection reporting requirements as they add transparency and accountability;
- Require the Large IOUs to include in monthly disconnection reports an anonymized breakdown of bundled and unbundled customers to inform broader disconnection prevention strategies;
- Require the Large IOUs to provide regular reports to individual CCAs of recently disconnected customers, or customers who are at risk of disconnection, to allow CCAs to contribute to customer outreach; and
- Develop a third-party, holistic study of payment plan and disconnection protection programs to determine existing program effectiveness and the need for reform.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING REQUIREMENTS OF SENATE BILL 1142 AND EXTREME HEAT DISCONNECTIONS PROTECTIONS

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Addressing Requirements of Senate Bill 1142 and Extreme Heat Disconnections Protections*[3] (Proposed Decision), dated May 9, 2025. The Proposed Decision addresses the requirements of Senate Bill (SB) 1142,[4] requiring electric and gas companies to restore service to a disconnected customer that agrees to certain payment plans.

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster 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 *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

3 [Proposed] *Decision Addressing Requirements of Senate Bill 1142 and Extreme Heat Disconnections Protections*, Rulemaking (R.) 18-07-005 (May 9, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K498/565498888.PDF.

4 Senate Bill No. 1142 (SB 1142) (Menjivar, Chapter 600, Statutes of 2024): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB1142.

SB 1142 also requires the Commission to determine whether to direct electric and gas corporations to consider a customer's ability to pay in certain disconnection and reconnection circumstances.

I. INTRODUCTION

Energy affordability issues continue to impact Californians, including those struggling to pay bills or having their electric service disconnected. The Proposed Decision adopts reasonable steps to protect customers from prolonged service disconnections, while also addressing significant levels of customer electricity arrearages. *First*, the Proposed Decision fairly establishes a reconnection framework that prioritizes first-time disconnected customers, requiring Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Large IOUs) to offer and enroll these customers in a payment plan as the only requirement for reconnection of service. *Second*, the Proposed Decision requires the Large IOUs to add reconnection data to the monthly disconnection reports submitted to the Commission, requiring the Large IOUs to report how many reconnections were performed at various time intervals as a measure of performance. For remote reconnections that take longer than 24 hours, or field reconnections that take longer than one business day, the Large IOUs must also provide a reason. The Proposed Decision also allows for Energy Division Staff to address observed underperformance in meeting those time thresholds.

CalCCA provides additional recommendations herein that should be incorporated into the Proposed Decision to allow community choice aggregators (CCAs) and others to contribute to preventing disconnections, support struggling customers, and reduce customer arrearages. *First*, the Large IOUs should be required to include in the monthly disconnection reports to the Commission an anonymized breakdown of the disconnection rate data by bundled and unbundled customers. This information can inform both broader customer targeting strategies and the Report on Residential Disconnections to the Legislature required by California Public Utilities

Code Section 910.5.[5] *Second*, the Proposed Decision should direct the Large IOUs to provide specific information regarding CCA customers to CCAs. With information on CCA customers at risk for disconnection or having been disconnected, CCAs may be able to assist in targeting those customers to provide additional support.

Finally, the Proposed Decision errs by not ordering a holistic third-party study of payment plans and disconnection protection programs. Despite the chorus of parties supporting this concept, the Proposed Decision opts to direct the Commission to continue reviewing the Percentage of Income Payment Plan (PIPP) Final Evaluation Report and the Arrearage Management Plan (AMP) Final Evaluation Report, which will be filed in October 2025. The Commission, however, does not need to wait for more individual evaluations before developing a broader, holistic study of payment plan and disconnection protection programs, the CalCCA respectfully recommends that the Commission:

- Approve the Proposed Decision's reconnection framework as it strikes a balance between protecting customers and addressing customer arrearages;
- Approve the Proposed Decision's reconnection reporting requirements as they add transparency and accountability;
- Require the Large IOUs to include in monthly disconnection reports an anonymized breakdown of bundled and unbundled customers to inform broader disconnection prevention strategies;
- Require the Large IOUs to provide regular reports to individual CCAs of recently disconnected customers, or customers who are at risk of disconnection, to allow CCAs to contribute to customer outreach; and
- Develop a third-party, holistic study of payment plan and disconnection protection programs to determine existing program effectiveness and the need for reform.

5 Cal. Pub. Util. Code § 910.5.

II. THE PROPOSED DECISION'S RECONNECTION FRAMEWORK SHOULD BE ADOPTED AS IT STRIKES A REASONABLE BALANCE BETWEEN PROTECTING CUSTOMERS AND ADDRESSING ARREARAGES

The Commission should approve the Proposed Decision's reconnection framework because it strikes a reasonable balance between protecting customers and addressing arrearages. The Proposed Decision requires the Large IOUs to reconnect first-time disconnection customers with no conditions beyond enrolling the customer in a payment plan.[6] The customer then receives additional disconnection protections for three months following the reconnection.[7] Focusing on customers who are disconnected for the first time not only fairly provides an opportunity for education of those customers to prevent future disconnections, but also lowers the risk that customers repeatedly take advantage of protections in place. The Proposed Decision also recognizes the need for the Large IOUs to examine customer situations on a case-by-case basis and provides discretion to the Large IOUs after three months following the first disconnection to work with individual customers.[8] Given the need to protect vulnerable customers and the need to manage and reduce overall arrearages in California, this reconnection framework is a balanced step forward, and the Commission should adopt it.

III. THE PROPOSED DECISION'S RECONNECTION REPORTING REQUIREMENTS FOR LARGE IOUS SHOULD BE ADOPTED AS THEY ADD A LAYER OF ACCOUNTABILITY AND TRANSPARENCY

The Proposed Decision's reconnection reporting requirements for the Large IOUs should be approved because they add a layer of accountability and transparency. The Proposed Decision requires the Large IOUs to include in the monthly disconnection reports the number of

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[6] *See* Proposed Decision, at 11-13 (describing reconnection protocols for first-time disconnected customers).

[7] *See id.*, Ordering Paragraph 1(a)-(b).

[8] *See id.*, at 14 (describing the complex and unique nature of customer situations that lead to disconnections).

reconnections at various time thresholds and the reasons for exceeding the 24-hour and one business day reconnection thresholds set for remote and field reconnections.[9] Reconnections are an important piece of the larger disconnection and arrearages framework that should be added to the existing reporting template. The additional requirement also allows a layer of accountability by providing information to Energy Division staff to investigate and refer underperformance regarding IOU reconnections to the Commission's Consumer Affairs Board.[10]

IV. THE IOUS SHOULD BE REQUIRED TO REPORT ON BOTH BUNDLED AND UNBUNDLED CUSTOMER DISCONNECTION RATES IN THE MONTHLY REPORTS TO INFORM BROADER DISCONNECTION PREVENTION STRATEGIES

The IOUs should be required to report disaggregated bundled and unbundled customer disconnection rates in the monthly disconnections report to inform broader disconnection prevention strategies. The monthly disconnection reports currently include IOU disconnection rates compared to the IOU's authorized disconnection rate caps. Breaking these disconnection rates out by bundled and unbundled customers will provide additional relevant information to stakeholders. If disconnections are disproportionately occurring in one sector over another, stakeholders can investigate and deploy education and outreach to vulnerable customers more effectively. More visibility into disconnection rates and which customers are most affected allows for further refinement of activities and programs to aid customers.

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9 *See id.*, at 22 (requiring the Large IOUs to report in monthly disconnection reports: (1) total number of reconnections, disaggregated by field and remote reconnections; (2) the number of remote reconnections that occur within 24, 48, 72, and more than 72 hours; (3) the number of field reconnections that occur in one, two, three or more than three business days; and (4) for all remote connections that take longer than 24 hours or field connections longer than one business day, an explanation for the delay).

10 *See id.*, at 22-23 ("If after the initial monthly report the data shows, or after several reports the data shows a trend, that a utility has objectively poor performance or underperforms its peers, the utility will be required to provide more detailed reporting, including the type of narrative reporting requested by Cal Advocates and TURN, CforAT, and NCLC. If poor performance or under performance continues, Energy Division staff may refer to the matter to CAB for investigation.").

V. THE IOUS SHOULD BE REQUIRED TO PROVIDE DISCONNECTION INFORMATION TO A CUSTOMER'S CCA TO ENABLE THE CCA TO PROVIDE ADDITIONAL OUTREACH

The Commission should require the IOUs to provide disconnection information to a customer's CCA to enable the CCA to provide additional outreach. With the necessary information, CCAs can assist in preventing disconnections through education regarding a customer's options, including payment programs. Therefore, the Commission should require the Large IOUs to provide regular reports to the CCAs on their customers that are soon to be or have recently been disconnected. CCAs are uniquely positioned to provide locally and culturally relevant messaging to their customers, which can help guide customers experiencing hardships that contribute to not making payments or getting disconnected. This information can also be used to inform organizations participating in the Community-Based Organization (CBO) Pilot currently underway.

It should be noted that these customer data are covered under the existing confidentiality agreements in place between Large IOUs and CCAs in their service areas. In fact, Southern California Edison Company (SCE) already provides this information to at least one CCA in its territory. The other Large IOUs could use SCE's report as a template, providing standardized information to efficiently deploy CCA resources across Large IOU service areas.

VI. A HOLISTIC STUDY OF PAYMENT AND DISCONNECTION PROTECTION PROGRAMS SHOULD BE PERFORMED TO IDENTIFY FURTHER PROGRAM SYNERGIES AND OPPORTUNITIES TO HELP CUSTOMERS

The Proposed Decision errs in not ordering a third-party, holistic study of disconnection protection and payment programs, or even describing a plan for informing or developing such a study. The Proposed Decision states that:

> Commission staff will review the PIPP Pilot Program Final Evaluation Report (filed and served by PG&E on March 17, 2025) and the AMP Final Evaluation Report (due October 1, 2025) and, if warranted, may recommend ways to improve the individual and collective effectiveness of the payment programs. The more that the Large IOUs can guide the AMP Evaluation to address the types of questions posed above, the more useful the Final Report will be.[11]

While CalCCA agrees that guiding the AMP study with the types of questions posed in the Proposed Decision is useful, the Commission already has enough evidence to rationalize pursuing a holistic study. Multiple other parties also support this concept, including SCE, PG&EPG&E, Southern California Gas Company, and the Public Advocates Office at the California Public Utilities Commission.

In particular, the Commission should recognize the existing lack of information about how programs affect each other, how customers see and interact with multiple programs, and the overall benefits that could be derived from consolidating program offerings into a more streamlined format. Studying individual programs is necessary and will identify insights, such as the conclusions from the PIPP Final Evaluation Report. For example, the PIPP Final Evaluation Report concluded that after the PIPP pilot has completed, the Commission should consider "a joint program that provides both energy bill payment assistance and arrearage forgiveness."[12] This finding directly points to the potential of combining programs to better aid customers, so further exploring this concept is essential. Additionally, non-Commission programs, such as the Low-Income Home Energy Assistance Program (LIHEAP), are currently in flux but are a valuable resource to low-income customers. All of these programs should be studied under a holistic review.

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11 *See id.*, at 31.

12 *Percentage of Income Payment Plan Pilot Program Final Evaluation Report,* R.18-07-005 (Mar. 17, 2025), Appendix A, at 79.

There is no need to wait until the AMP Final Evaluation Report in October 2025 to consider whether there is a need for further research. The Commission should develop a holistic study identifying ways to consolidate, streamline, and optimize customer offerings to prevent disconnections and reduce arrearages. At minimum, the AMP evaluation that is underway should incorporate recommendations from the PIPP Final Evaluation Report.

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests the adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the proposed decision as provided in Appendix A, attached hereto.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

May 29, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING REQUIREMENTS OF SENATE BILL 1142 AND EXTREME HEAT DISCONNECTIONS PROTECTIONS

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **<u>bold and underlined</u>**

FINDINGS OF FACT

<u>16. It is reasonable to pursue a holistic third-party study of payment plans and disconnection protection programs to enhance customer protection and further address arrearages.</u>

<u>17. It is reasonable to direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company to utilize the customer disconnections report template created by Southern California Edison Company to regularly share information on customers who will soon be or have recently been disconnected with community choice aggregators in their service area.</u>

CONCLUSIONS OF LAW

ORDERING PARAGRAPHS

New Order:

<u>7. The Commission will develop a Request for Proposals from third-party evaluators to perform a holistic study on disconnection prevention and payment plan programs to uncover potential improvements, efficiencies, and synergies among such programs.</u>

<u>8. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must provide reports to the community choice aggregators in their service areas on a monthly basis listing customers recently disconnected or will soon be disconnected, using Southern California Edison Company's existing report to CCAs as a template.</u>

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California State Senate

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LOCAL GOVERNMENT
PUBLIC SAFETY
JOINT RULES

May 30, 2025

Alice Busching Reynolds, President
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: Self-Generation Incentive Program and Harm to Community Choice Aggregators Customers

Dear President Reynolds:

We write to request that the CPUC immediately review and approve the submitted CCA demand-response program advice letters for SGIP.

The 2023 Budget Act provided $280 million for the program, and we are dismayed that, more than two years later, the CPUC has yet to approve allocation of the funds to communities throughout California. Now more than ever, at a time when ratepayers are facing increased costs and the status of other climate funds are uncertain, we expect state agencies to move with alacrity in getting funds out the door in an expedient, efficient, and equitable manner.

The Self-Generating Incentive Program (SGIP) is an essential program that provides financial rebates for energy storage systems and other distributed energy resources (DERs), that are vital to meet California's increasingly complex reliability, distribution and transmission, climate, and affordability needs.[1] Originally launched in 2001, SGIP is designed to serve residential and non-residential customers statewide.

[1] Public Utilities Code section 379.6.

In 2018, the Legislature passed SB 700 (Wiener, Chapter 839, Statutes of 2018) which extended the SGIP program for five years through 2025. SB 700 continued savings for ratepayers across the state, from the installation of more than 2,000 MW of storage capacity in order to meet the state's increasing energy, replacing fossil fuels, and further enabling the deployment of variable renewable energy sources. The Legislature explicitly directed the CPUC to offer the program to all ratepayers, "The commission shall ensure that distributed generation resources are made available in the program for all ratepayers."[2]

All California ratepayers pay into the SGIP program,[3] and the Legislature intended all Californians to be eligible to benefit from the program.[4] Unfortunately, the program's current implementation, especially as it relates to the 2023 Budget Act allocation, unfairly prevents many from participating. Specifically, the current implementation of SGIP impermissibly denies the nearly 1/3 of Californians served by CCAs access to the SGIP rebates that they help fund.[5] We are concerned to hear from our constituents that, in addition to denying CCA customers beneficial rebate access, the current implementation of SGIP also unjustifiably imposes cost increases on CCA customers in an increasingly challenging energy affordability crisis.[6]

The CPUC must act immediately to allow pathways for CCA customers to access SGIP and prevent further financial harm to current and former CCA customers. The Commission has the authority under current law and the responsibility to update its implementation of the "qualified demand response program" enrollment requirements.[7]

<u>Qualified Demand Response Program Enrollment Requirement</u>

To better support SGIP's programmatic goals, the Legislature directed the Commission to consider requiring SGIP participants to enroll in a, "demand response program or a peak load reduction program offered through the customer's load-serving entity[.]"[8] The law does not require participation in demand response programs, but rather that the CPUC must ***<u>consider</u>***

[2] Senate Bill 700 (2018), section (i).
[3] Funding sources include ratepayer funds, greenhouse gas reduction funds and in some cases general funds appropriated by the Legislature.
[4] Assembly Bill 209 (2022), Section 25, "It is the further intent of the Legislature that the commission, in future proceedings, provide for an equitable distribution of the costs and benefits of the program."
[5] CalCCA, California Aggregator, 2024, p. 4, available at: https://cal-cca.org/wp-content/uploads/2024/01/California-Aggregator-Winter-2024-Newsletter.pdf?utm_source=chatgpt.com ("CCAs are procuring energy resources for over 14 million customers in California, about one-third of the state's population.").
[6] CPUC, 2024 Senate Bill 695 Report, pp. 1-3 available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf.
[7] CPUC, Decision (D.)24-03-071, pp. 3, 75-76.
[8] Public Utilities Code section 379.10 (b).

participation in demand response programs *or* in peak load reduction programs. The Legislature appropriated $280 million in greenhouse gas reduction funds, and extended the collection of ratepayer funds for the program.[9]

Subsequently, the Commission issued two key decisions to disburse funds and update implementation of the SGIP program. In Decision (D.) 23-12-005 the CPUC created a definition of a "qualified demand response program" and outlined an advice letter process to add programs. In D.24-03-071 three months later, the Commission revised its previous decision and added a new list of qualified demand response programs exclusively for SGIP.[10] In addition to creating confusion and unnecessary complexity for customers and program administrators, the latter decision only qualifies a handful of investor-owned utility (IOU) programs. These programs are unavailable to residential CCA customers. No CCA customer may self-enroll in any of these qualified demand response programs in order to access SGIP.[11] Consequently, no CCA customer has accessed SGIP rebates since the implementation of this decision statewide. We are disheartened to learn that despite significant CCA, developer, and customer engagement[12] with the Commission on this issue, no solution has been offered to CCA customers.

Harms to CCA Customers

Due to the CPUC's implementation of SGIP qualified demand response program requirements, CCA residential customers, unlike IOU customers, cannot access their share of the $280M in SGIP incentives approved by the Legislature in the 2023-24 budget when they become available on May 20th. This is in spite of the fact that CCA residential customers pay into the program.

The CPUC's implementation of SGIP qualified demand response program requirements harm CCA customers in several ways. Many CCA customers, after being directed by SGIP project developers or interpreting vague program rules themselves, opted out of CCA service in order to access SGIP. Customers who opt out of CCA service are placed on a 6 month transitional rate that is extremely volatile and prohibits enrollment in IOU administered SGIP qualified demand response programs.[13] Several of these customers experienced higher energy bills and lost access

[9] Assembly Bill 209 (2022); Assembly Bill 102 (2023); CARB, California Climate Investments, available at: https://ww2.arb.ca.gov/our-work/programs/californiaclimate-investments/about.
[10] D.24-03-071, Appendix E.
[11] Pacific Gas & Electric filed an advice letter to update its CBP program so unbundled customers may enroll and access SGIP. The Commission has failed to issue a timely disposition on the advice letter. PG&E AL 7548-E (December 2024).
[12] CCAs raised this issue with the Commission several times in written submissions, meetings, and by providing supplemental information on numerous occasions. Multiple CCAs have also submitted their own programs to be added to the qualified demand response programs list for SGIP and none have received an approval disposition as of this date.
[13] IOU generation rates are presently higher than many CCA generation rates.

to CCA bill discounts and other beneficial programs. Customers have been charged as much as 4 times their previous energy bills. Many of these customers were unaware they would be unable to enroll in a qualified demand response program for 6 months and are now at risk of missing the opportunity to enroll in the program before SGIP sunsets in 2026. Customers who find themselves stuck in this situation are not permitted to return to CCA service for a full year. As a result, customers are now experiencing significantly higher bills, unable to access SGIP, and unable to choose their preferred load-serving entity. Low-income customers, who are able to stack SGIP rebates with other programs such as the Transformative Climate Communities funds, are particularly hit hard by these delays which in turn further frustrates the implementation of other climate funds.

<u>The Solution</u>

We are concerned to hear that the CPUC's actions and implementation of these funds is resulting in inequitable outcomes and raising costs for CCA customers. This is not our intent. We request that Energy Division staff efficiently and effectively review CCA demand response program advice letters no later than 30 days following their protest period.[14]

Thank you for your consideration of our concerns and your attention to this important matter. Please feel free to reach out to me with any questions, or if your staff have questions, please do not hesitate to contact Radhika Gawde in my office at Radhika.gawde@sen.ca.gov or 916-651-4011.

Sincerely,

Scott Wiener

Scott Wiener
Senator, 11th District

Monique Limon
Senator, 21st District

Aisha Wahab
Senator, 10th District

[14] Equivalent to 50 days following the submission of an advice letter.

Jesse Arreguín
Senator, 7th District

Ben Allen
Senator, 24th District

Stephen Padilla
Senator, 18th District

Jerry McNerney
Senator, 5th District

Jacqui Irwin
Assembly Member, 42nd District

Rhodesia Ransom
Assembly Member, 13th District

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CC:
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Matt Baker, Commissioner, CPUC
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