AUGUST FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.	Rulemaking 20-05-012

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON ASSIGNED COMMISSIONER'S RULING SEEKING ADDITIONAL COMMENTS ON SELF-GENERATION INCENTIVE PROGRAM AND HEAT PUMP WATER HEATER PROGRAM IMPROVEMENTS

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On behalf of Joint Community Choice Aggregators

August 1, 2023

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON ASSIGNED COMMISSIONER'S RULING SEEKING ADDITIONAL COMMENTS ON SELF-GENERATION INCENTIVE PROGRAM AND HEAT PUMP WATER HEATER PROGRAM IMPROVEMENTS

Pursuant to the Assigned Commissioner's July 12, 2023 Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater (SGIP and HPWH) Program Improvements (July ACR), the Joint Community Choice Aggregators[1] (Joint CCAs) hereby submit these Opening Comments on the July ACR. In these comments, the Joint CCAs address only Question #5 from the July ACR. The Joint CCAs reserve their right to respond to parties' opening comments on other questions in the July ACR.

I. COMMENTS

Question #5 in the July ACR asks:

> Should certain existing DR programs be considered as qualified programs so that customers enrolling in these programs are eligible for the SGIP HPWH program? What should be the criteria to consider a DR program as a qualifying program under the SGIP HPWH Program rules?

The Joint CCAs recommend the Commission update the definition of a qualifying demand response (DR) program to broaden eligibility for the SGIP HPWH program and promote customer choice. Moreover, the Joint CCAs believe that broadening the definition of a qualifying DR

[1] The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), Sonoma Clean Power Authority (SCP), and the City of San Jose.

program—and thereby allowing SGIP HPWH program participants to enroll in a broader array of DR programs—is timely, given the reliability challenges facing the grid and the valuable role that DR plays in mitigating those challenges.

As the July ACR recognizes, the current definition of a qualifying DR program is limited to California Independent System Operator (CAISO) market-integrated supply-side DR programs that count for resource adequacy. This narrow definition excludes a range of *load modifying* DR programs currently available to HPWHs. Community Choice Aggregators (CCAs) already administer—and plan to launch—several load-shifting programs available to HPWHs. For instance, several CCAs are administering "FLEXmarket" programs that install energy efficiency (EE) measures for daily load-shifting out of the peak hours to support grid reliability. Examples include MCE's Commercial and Residential Efficiency Markets,[2] MCE's Peak FLEXmarket Program,[3] and PCE's FLEXmarket Program.[4] Rather than optimizing usage according to a time-of-use (TOU) rate, FLEXmarket programs optimize usage by paying incentives according to the avoided cost value of load shifted, or energy saved. The FLEXmarket programs provide incentives for a variety of EE measures, including HPWHs, and pay for the actual grid value of energy savings they deliver. HPWHs that participate in the FLEXmarket programs have the potential to reap significant benefits from participation in the programs as incentives are based on the expected useful life (EUL) of measures which calculates out incentives paid to customers based on the benefits expected from the measures over their lifespan. The Joint CCAs anticipate more CCAs will administer load-shifting programs in the future and that current program offerings will continue to evolve.

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[2] https://www.mcecleanenergy.org/flexmarket/.
[3] https://www.mcecleanenergy.org/peak-flexmarket/.
[4] https://www.demandflexmarket.com/pce.html.

In the interest of promoting customer choice and flexibility, and encouraging enrollment in a range of DR programs that deliver load reductions, the Joint CCAs recommend the Commission broaden the definition of "qualifying DR program" to include load-modifying DR programs (both event-based and daily load-shifting programs). Moreover, to the same end, the Joint CCAs request the Commission clarify that the definition of a "qualifying DR program" applies irrespective of whether the DR program administrator is an investor-owned utility (IOU), CCA, or a third-party DRP (Demand Response Provider).

II. CONCLUSION

The Joint CCAs appreciate this opportunity to provide comments on the July ACR. The Joint CCAs recommend the Commission update the definition of a "qualifying DR program" to include both CAISO market-integrated and load-modifying programs; event-based and daily load-shifting programs; and IOU-administered and non-IOU-administered (CCA and third party DRP) programs.

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Dated: August 1, 2023

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

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Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	Rulemaking 23-01-007

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REQUEST FOR EVIDENTIARY HEARINGS AND LEGAL BRIEFING**

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August 9, 2023

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COMMISSION RULES OF PRACTICE AND PROCEDURE

SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should set Phase 1 Track 2 of this matter for evidentiary hearing.

- The Commission should allow parties to file opening and reply briefs on Phase 1 Track 2 issues on the dates specified in the Assigned Commissioner's April 6, 2023 Scoping Memo and Ruling.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations.	Rulemaking 23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REQUEST FOR EVIDENTIARY HEARINGS AND LEGAL BRIEFING

The Assigned Commissioner's April 6 Scoping Memo and Ruling directs parties to request evidentiary hearings and/or briefs in Phase 1 Track 2 of this proceeding by August 9, 2023. Accordingly, California Community Choice Association[1] (CalCCA) submits this request for both evidentiary hearings and briefs in Rulemaking (R.) 23-01-007, *Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations.*

As CalCCA explains below, certain disputed facts in this proceeding would benefit from further record development through an evidentiary hearing. While CalCCA has made efforts to narrow those disputed facts, and will continue to make efforts to narrow those disputed facts before the evidentiary hearing, CalCCA does not believe a meet and confer process or other dispute resolution process will be sufficient to resolve the facts in dispute. CalCCA also explains below that certain legal issues in this proceeding, including legal issues raised for the first time in parties' rebuttal testimony, would benefit from argument in briefs. CalCCA therefore believes that both

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Energy For Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

evidentiary hearings and legal briefing would assist the Commission in arriving at a decision in Phase 1 Track 2 of this proceeding.

I. REQUEST FOR HEARING

As directed in the Assigned Commissioner's April 6 Scoping Memo and Ruling, CalCCA provides below: 1) specific facts in the case that are in dispute; 2) prior efforts made to narrow the facts in dispute, and 3) whether a meet and confer process and/or other dispute resolution alternatives would be able to resolve the facts in dispute.

A. Parties Dispute Numerous Facts Material to the Case's Resolution.

The parties August 8, 2023 Joint Statement[2] filed in this proceeding illustrates that most of the scoping issues in Phase 1 Track 2 of this proceeding remain disputed. Those include the following issues, on which CalCCA has submitted testimony in this proceeding:

3. If the Commission directs and authorizes extended operations at Diablo Canyon, what are the new processes to authorize annual recovery of all reasonable Diablo Canyon extended operations costs and expenses on a forecast basis, including allocation of forecast costs among Commission-jurisdictional load-serving entities.

4. Whether additional cost recovery mechanisms, agreements, issues, plans, and/or orders are needed prior to the current retirement dates for Diablo Canyon Units 1 and 2 (i.e. in 2024 and 2025, respectively).

5. Whether and how the benefits of extended operations, including resource adequacy and greenhouse gas-free attributes, should be allocated among the load-serving entities (LSEs) and customers paying for extended operations.

Within those broad scoping issues, CalCCA has identified the following list of specific facts in this case that remain in dispute:

1. The degree to which allocating resource adequacy (RA) capacity from Diablo Canyon Power Plant (DCPP) will cause incremental costs or obligations for Pacific Gas and Electric Company (PG&E) relative to its current costs or obligations (under Scoping Issue 5);

2 R.23-01-007, Joint Statement Following Rule 13.9 Meet and Confer by Pacific Gas and Electric Company (U 39 E) on Order Instituting Rulemaking to Consider Potential Extension of Diablo Canyon Power Plant Operations in Accordance with Senate Bill 846 at 3-6 (Aug. 8, 2023) (Joint Statement).

2. Whether allocating RA capacity from DCPP eliminates the incentive for load serving entities (LSEs) to procure new resources or increases the potential for existing resources to be retired and exit the market (under Scoping Issue 5);

3. Whether DCPP RA capacity should be allocated during months when there is a known/foreseeable maintenance outage (under scoping issue 5);

4. Whether allocating RA based on "12 Coincidental Peak" (12CP) or load share would most accurately convey the benefits of DCPP (under scoping issue 5);

5. Whether allocating greenhouse gas-free (GHG-free) energy attributes from DCPP's extended operations would impact LSEs' ability or incentive to meet the state's long-term decarbonization goals (under scoping issue 5);

6. Whether allocating GHG-free energy attributes from DCPP's extended operations would impact the pace at which LSEs bring clean energy resources online (under scoping issue 5);

7. The magnitude of any incremental costs and administrative obligations caused by the allocation of GHG-free energy attributes from DCPP to all Commission-jurisdictional LSEs, relative to the costs associated with PG&E's existing interim allocation process (under scoping issue 5); and

8. Whether allocating the costs of DCPP extended operations on 12CP or load share is more accurate (under scoping issues 3 and 4).

CalCCA believes that a half-day hearing (as opposed to the three days blocked for evidentiary hearings in the Assigned Commissioner's Scoping Ruling) could be sufficient to address the disputed issues above.

B. Prior Efforts Have Been Made and Will Continue to Be Made to Narrow the Facts in Dispute.

CalCCA attended and participated in a Rule 13.9 Meet and Confer on August 7, 2023.[3] Among other things, the purpose of that Meet and Confer was to make efforts to narrow the facts in dispute.[4] Following a discussion, parties determined it was infeasible to narrow disputed facts

[3] *See* Joint Statement at 1.
[4] *Id*. at 5.

at that time, given the expedited timeline and range of disputes in the proceeding.[5] CalCCA will continue to make efforts to narrow the remaining disputed facts in this proceeding, including by meeting and conferring with the parties, and by issuing discovery and pursuing stipulations, to the extent feasible.

C. A Meet and Confer Process and/or Other Dispute Resolution Alternatives Are Unlikely to Resolve All Material Facts in Dispute.

The disputed issues identified above, however, are material, and based on the testimony submitted by parties in this proceeding to date, the gap between the parties on those issues is substantial. Moreover, the timeline in this proceeding is constrained by the statutory requirement that the Commission must establish new retirement dates for DCPP by December 31, 2023.[6] Therefore, even if a meet and confer process and/or other dispute resolution alternative could resolve the facts in dispute, CalCCA does not believe that such a process is feasible under the timeline of this proceeding.

II. REQUEST FOR LEGAL BRIEFING

At least one legal issue in Phase 1 Track 2 of this proceeding requires briefing: *Whether allocating RA and GHG attributes contravenes or complies with the letter and spirit of SB 846 and other State law?* That legal issue is directly relevant to Phase 1 Track 2 scoping issue 5: "Whether and how the benefits of extended operations including resource adequacy and greenhouse gas-free attributes, should be allocated among the load-serving entities (LSEs) and customers paying for extended operations."

While several parties have discussed or alluded to their legal positions in testimony, briefing is the most appropriate avenue for parties to make arguments on legal issues, including

[5] *Id*.
[6] Cal. Pub. Util. Code § 712.8(c)(2)(A).

the legal issue it identifies above. In fact, certain parties raised legal arguments in their final round of testimony,[7] meaning legal briefing is the *only* avenue for CalCCA to respond to those legal arguments. CalCCA therefore requests the Commission adopt the dates for opening and reply briefs listed in the Assigned Commissioner's Scoping Memo and Ruling (September 15, 2023 for opening briefs and September 29, 2023 for reply briefs).

III. CONCLUSION

For the reasons described herein, CalCCA respectfully requests the Commission set this matter for evidentiary hearing and allow the parties the opportunity to file opening and reply briefs on the schedule outlined in the Assigned Commissioner's April 6 Scoping Memo and Ruling.

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August 9, 2023

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[7] *See, e.g.* R.23-01-007, Prepared Rebuttal Testimony on behalf of the Alliance for Nuclear Responsibility of John Geesman at 2-5 (Aug. 28, 2023) (opining on the correct interpretation of, and legislative intent behind, SB 846).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

JOINT COMMUNITY CHOICE AGGREGATORS' REPLY BRIEF ON PHASE II ISSUES

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On behalf of Joint Community Choice Aggregators

August 11, 2023

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SUMMARY OF RECOMMENDATIONS

- The Commission should initiate a dual participation working group no later than 30 days following its Phase II decision.
- The Joint CCAs request the Commission direct the utilities to exchange DR program participation information with CCAs in order to facilitate a comprehensive dual enrollment prevention process for all DR programs, the *mechanics* and *implementation* of which will be developed through the dual participation working group.
- The Joint CCAs request the Commission establish a minimum_scope for the dual participation working group through its Phase II decision, including the development of (1) a bilateral customer participation data exchange process and (2) an efficient and consistent customer disenrollment process where dual participation is identified.
- The Joint CCAs request the Commission require parties to file dual participation proposals for the Commission's consideration by the end of January 2024, and issue a decision on those proposals by April 1, 2024, to allow the implementation of those proposals in time for the summer 2024 season.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

JOINT COMMUNITY CHOICE AGGREGATORS' REPLY BRIEF ON PHASE II ISSUES

Pursuant to the revised procedural schedule established in the January 27, 2023 *Assigned Commissioner's Ruling Directing Response to Questions and Energy Division Staff Proposals Related to Application 22-05-002 Phase II Issues and Directing Southern California Edison Company to Submit a Capacity Bidding Program Elect Proposal for Program Years 2024-2027* (January ACR), and the June 28, 2023 *Administrative Law Judge's Ruling Admitting Testimony and Exhibits into the Record and Extending Due Dates for Opening and Reply Briefs on Phase II Demand Response Issues*, the Joint Community Choice Aggregators[1] (Joint CCAs) hereby submit this Reply Brief on Phase II Issues.

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[1] The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the City of San José – which operates and administers San José Clean Energy (SJCE) through the City's Community Energy Department, and Sonoma Clean Power Authority (SCP). SJCE is the City of San José's CCA program, which the San José Community Energy Department administers. Each of the CCAs in the Joint CCAs is located in Northern California, and therefore focus their testimony and participation in this proceeding on issues relevant to Pacific Gas & Electric Company's (PG&E) Application for Approval of its Demand Response Programs, Pilots, and Budgets for Program Years 2023-2027 (Application).

I. INTRODUCTION

The Joint CCAs support Pacific Gas & Electric Company's (PG&E) proposed "dual participation working group" to revisit the currently applicable, but outdated, demand response (DR) dual participation rules.[2] Parties' opening briefs demonstrate broad agreement[3] that a dual participation working group is not only a good idea but a priority given both the diversification of California's DR landscape and the significant role that DR now plays in helping the state meet its reliability and climate objectives. The Commission should therefore initiate a dual participation working group no later than 30 days following its Phase II decision.

The parties' disagreement with respect to a dual participation working group boils down to the actions the Commission should take in its Phase II decision in this instant proceeding. In order to ensure the dual participation working group—which, based on parties' briefing, will necessarily tackle a broad range of complex topics—is productive and timely, the Joint CCAs recommend the Commission issue specific directives in its Phase II decision regarding the outputs it expects from the dual participation working group, and the timeline on which it expects that working group to conclude. The Joint CCAs specifically request the Commission direct the utilities to exchange DR program participation information with CCAs in order to facilitate a comprehensive dual enrollment prevention process for all DR programs, the *mechanics* and *implementation* of which will be developed through the dual participation working group.[4] The Joint CCAs also request the Commission establish a minimum scope for the dual participation working group through its Phase II decision, including the development of (1) a bilateral customer participation data exchange

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2 Joint CCAs Opening Brief at 5.

3 *See* PG&E Opening Brief at 13-15; San Diego Gas and Electric Company (SDG&E) Opening Brief at 54; Public Advocates Office (Cal Advocates) Opening Brief at 19-20; Vehicle Grid Integration Council (VGIC) Opening Brief at 13; California Large Energy Consumers Association (CLECA) Opening Brief at 34.

4 Joint CCAs Opening Brief at 5, 8.

process and (2) an efficient and consistent customer disenrollment process where dual participation is identified.[5] Finally, the Joint CCAs request the Commission require parties to file dual participation proposals for the Commission's consideration by the end of January 2024, and issue a decision on those proposals by April 1, 2024, to allow the implementation of those proposals in time for the summer 2024 season.

In contrast, PG&E does not recommend the Commission issue specific directives with respect to the dual participation working group in its Phase II decision. Instead, PG&E offers a series of principles for an updated dual participation policy[6] and a "non-exhaustive list of dual participation issues that require thoughtful consideration."[7] The Joint CCAs do not fundamentally disagree with any of PG&E's principles or issues,[8] but recommend the Commission provide more concrete guidance through its Phase II decision in order to give the participants in the dual participation working group a common starting point. Moreover, the concrete directives the Joint CCAs request in no way preclude the working group participants from discussing and refining the *mechanics* and *implementation* of data exchange or customer disenrollment through the working group process. The Joint CCAs therefore request the Commission adopt the recommendations in the Joint CCAs' Opening Brief.

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5 *Id*. at 5.

6 PG&E Opening Brief at 13-14.

7 *Id*. at 14-15.

8 Joint CCAs address the first item listed in PG&E's "non-exhaustive list of dual participation issues" (regarding whether dual participation rules should be broadened to other load management solutions) in Section II.C. of this brief.

II. REPLY TO PG&E

A. The Commission Should Direct the Utilities to Share DR Program Customer Participation Information with Community Choice Aggregators (CCAs) In Order to Facilitate Dual Participation Prevention, and Should Establish a Minimum Scope and Timeline for the Dual Participation Working Group.

In its Opening Brief, PG&E argues that the Joint CCAs' proposed data exchange and customer disenrollment processes "may be appropriate subject for dual participation workshops and working groups, but they are not appropriate for a Phase II decision without further stakeholder input and analysis."[9] On this premise, PG&E offers the Commission two options to "develop a record to provide the foundation for a decision regarding CCA-utility data sharing issues."[10] PG&E's record development option 1 is for parties to "develop proposals that address privacy and operational issues that may foster two-way information exchange" as a part of the dual participation working group following this proceeding.[11] PG&E's record development option 2 is "a comprehensive review of litigation arguments regarding data release in a single forum, either in a Phase III or a Phase of another proceeding."[12]

As a threshold matter, PG&E's suggestion that the Joint CCAs' proposals are "not in scope of Phase II" is incorrect and likely the product of PG&E misunderstanding the Joint CCAs' recommendations. Phase II Scoping Issue 9 asks: "Should dual participation rules be modified or clarified?"[13] PG&E,[14] the Joint CCAs,[15] and several other parties[16] submitted record evidence collectively explaining that dual participation rules must be modified and addressing the

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9 PG&E Opening Brief at 15.
10 *Id*. at 16.
11 *Id*.
12 *Id*.
13 Assigned Commissioner's Amended Scoping Memo and Ruling and Assigned Administrative Law Judges' Ruling on Two Motions at 6 (Dec. 19, 2022) (establishing Phase II Scoping Issues for 2024-2027 Utilities' Demand Response Programs).
14 Exhibit PGE-02 at 2-9.
15 Exhibit JCCA-01 at 3-8.
16 Exhibit Council-02 at 12; Exhibit Cal Advocates-01 at 2-2 – 2-3; Exhibit CLECA-01 at 31.

deficiencies in existing data exchange and customer disenrollment processes. Such data exchange and customer disenrollment processes are *required* to prevent dual participation in DR programs and are intrinsic to, and in the scope of, the discussion of dual enrollment rules. Furthermore, parties have had ample opportunity to brief these issues. No party—including PG&E—has opposed the basic proposition that effective data exchange and disenrollment processes would be valuable and help facilitate dual participation prevention. Therefore, while the *mechanics* and *implementation* of a data exchange or customer disenrollment process might benefit from stakeholder input via a working group (for instance – how the data exchange is best implemented and at what cadence), the record allows the Commission to *direct the development* of those processes and thereby establish a common "starting point" for the dual participation working group process. The Joint CCAs therefore continue to recommend the Commission, in its Phase II Decision:

- Direct the utilities to share DR program customer participation information with CCAs in order to facilitate dual participation prevention;
- Establish a minimum scope for the dual participation working group, including (1) the development of a bilateral customer participation data exchange process for load modifying DR programs between IOUs and CCAs (and other entities as needed), and (2) the development of an efficient and consistent customer disenrollment process where dual participation is identified, and;
- Require parties to file dual participation proposals for the Commission's consideration by the end of January 2024, and issue a decision on those proposals by April 1, 2024, to allow the implementation of those proposals in time for the summer 2024 season.

Again, none of these directives would preclude the parties from refining the *mechanics* or *implementation* of a data exchange or customer disenrollment process via the dual participation working group. Nor would these directives preclude the parties from resolving any legitimate[17] privacy or operational concerns associated with customer data exchange or disenrollment via the dual participation working group process. Rather, these directives would simply help avoid a foreseeable situation where certain parties attempt to relitigate the *merits* of utility-CCA data exchange during the dual participation working group, despite having had ample opportunity to do so during Phase II of this proceeding. Moreover, these directives would help ensure the development of data exchange and disenrollment processes is not unduly delayed, and that those processes are implemented in time for the summer 2024 season.

With respect to PG&E's two proposed record development options, Joint CCAs do not support option 2 (review of litigation arguments in a separate forum) because it is not clear what a "comprehensive review of litigation arguments" means, and because such a review might unnecessarily duplicate the parties' efforts in this Phase II and delay the implementation of data exchange and disenrollment processes. The Joint CCAs believe that PG&E's record development option 1 (parties develop proposals to foster two-way information exchange as a part of the dual participation working group), is consistent with the Joint CCAs' recommendation in opening brief.

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[17] The Joint CCAs note that certain of PG&E's professed concerns do not require resolution during the dual participation working group process. For instance, PG&E asserts that the Joint CCAs' customer disenrollment proposal "appears to create inconsistencies with the Commission's process for competitive neutrality, which requires CCAs to submit a Tier 3 advice letter stating that the IOU offers a similar program to theirs, and upon approval, provides for a year-long process to unenroll the customer." PG&E Opening Brief at 16. PG&E's concern risks distraction and is misplaced. The Commission's competitive neutrality process is primarily concerned with avoiding duplicative cost recovery for overlapping DR programs, and the unenrollment process is related to terminating the IOU's DR program offering in the CCA's entire service area. Adhering to this process, as PG&E proposes, would have significant unintended consequences. If CCAs followed the competitive neutrality process, and filed a Tier 3 advice letter which was approved, the IOU would not simply have to unenroll a single dually enrolled customer; they would have to unenroll all DR customers in their program throughout the CCA's service area, whether or not they were currently enrolled in the CCA DR program. Such an approach undermines the Commission's objective in addressing dual enrollment of single customers while maximizing customer demand flexibility and participation in DR programs. As such, there would be no inconsistency between the Joint CCAs' proposed disenrollment process and the Commission's competitive neutrality process, should the Joint CCAs' proposed disenrollment process be adopted.

B. The Commission Should Not Expand the Scope of the Dual Participation Working Group Beyond Demand Response.

Among other issues requiring "thoughtful consideration," PG&E asks whether "dual participation rules should be broadened to other load management solutions (i.e., EE [energy efficiency], pay-for-performance, etc.)?"[18] The Joint CCAs do not dispute this issue requires thoughtful consideration, but recommend discussion of this issue outside of the dual participation working group proposed in this instant proceeding. Dual enrollment prevention between multiple DR programs is a familiar concept, and one that requires an urgent revisit given the rapid growth in both the Emergency Load Reduction Program (ELRP) and other load-modifying DR programs in response to summer reliability concerns. Notwithstanding its potential merits, expanding dual enrollment prevention beyond DR to other DER related programs or tariffs (such as EE or real-time rates) is a new concept, and would introduce significant complexity to the dual participation working group. To avoid unduly slowing down the working group process focusing on DR dual enrollment issues, the Joint CCAs recommend that topics concerning dual enrollment between DR and other DER-related programs or tariffs to be discussed in the Commission's DER proceeding (R.22-11-013, *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards*").

III. CONCLUSION

For the reasons described in this brief and in the Joint CCAs' prior submissions in this proceeding, the Joint CCAs recommend the Commission adopt the recommendations in the Joint CCAs' Opening Brief.

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18 PG&E Opening Brief at 14.

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Pursuant to the Assigned Commissioner's July 12, 2023 *Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements* (July ACR), the Joint Community Choice Aggregators[1] (Joint CCAs) hereby submit these Reply Comments on the July ACR. The Joint CCAs address only Questions #4 and #5 from the July ACR in these Reply Comments.

I. THE JOINT CCAS SUPPORT ENERGY SOLUTIONS' PROPOSED DEFINITION OF A QUALIFIED DEMAND RESPONSE PROGRAM WITH MODEST CLARIFYING MODIFICATIONS

In its Opening Comments, Energy Solutions,[2] the program administrator/program implementer (PA/PI) of the Self-Generation Incentive Program (SGIP) heat pump water heater (HPWH) program, proposes the following definition for a "qualified" demand response (DR) program:

> *A program may meet one or more of the following eligibility criteria, each of which is independent of one another:*
>
> 1. *Any DR program that meets the current Decision definition of a qualified demand response program.*

[1] The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), Sonoma Clean Power Authority (SCP), and the City of San Jose.
[2] Cohen Ventures, Inc. d/b/a Energy Solutions (Energy Solutions).

2. *Any DR program or pilot offered by a load-serving entity or demand response provider that directly signals the incentivized technology (HPWHs) to shift or modify load, including load shifting programs.*
3. *Any DR program or pilot offered by a publicly-owned electric utility (POU).*
4. *Any DR program or pilot approved by the program implementer that is submitted via an application process from a load-serving entity or demand response provider.*[3]

The Joint CCAs support Energy Solutions' proposed definition with modest clarifying modifications. Energy Solutions' proposed definition—in particular, criterion 2—prudently accommodates load-modifying DR programs, including event-based and daily load-shifting programs, and would apply irrespective of whether the DR program administrator is an IOU, CCA, or a third-party demand response provider (DRP). The Joint CCAs recommend the Commission adopt Energy Solutions' definition with the following clarifying modifications to criterion 2:

> *Any load-modifying DR program or pilot offered by a load-serving entity or demand response provider that directly signals the incentivized technology (HPWHs) to shift or modify load, including event-based and daily load shifting programs.*

The Commission should adopt Energy Solutions' proposed definition with these modifications as it would address and resolve the Joint CCAs' recommendation regarding the definition of a "qualifying DR program" made in Opening Comments.[4] Other parties such as the California Efficiency + Demand Management Council (the Council) similarly support expanding the definition of qualifying DR programs beyond California Independent System Operator (CAISO) market-integrated DR programs.[5] The Council wisely explains, the Commission can

[3] Opening Comments of Cohen Ventures Inc. DBA Energy Solutions on Assigned Commissioner's Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements at 5-7 (Aug. 1, 2023).
[4] *See* Opening Comments of the Joint Community Choice Aggregators on Assigned Commissioner's Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements at 1-3 (Aug. 1, 2023).
[5] Opening Comments of California Efficiency + Demand Management Council at 5-7 (Aug 1, 2023).

expand the definition while simultaneously "retain[ing] the rigor of market integrated programs but incorporate[ing] the flexibility necessary for other scenarios and resources to participate in the SGIP HPWH Program."[6] The Joint CCAs agree.

Load-modifying DR programs meeting Energy Solutions' definition for a "qualifying DR program" as outlined in criterion 2 above can be just as stringent as CAISO market-integrated programs, well-aligned with grid reliability needs, and provide additional grid benefits. In fact, the utilities, the Commission and the State of California individually and collectively have made great investments in the development of load-modifying DR programs in recent years.

For example, the utilities' Emergency Load Reduction Program (ELRP)[7] functions largely as a load-modifying DR program to date. While the ELRP allows for both load-modifying participation (Group A) and CAISO market-integrated participation (Group B), the majority of historic participation occurred under the load-modifying pathway (in 2022, over 1.5 Million customers participated in Group A of the ELRP compared to only 580 customers participating under Group B.[8] The Commission has identified ELRP as a valuable "insurance" program in times of grid stress on numerous occasions.[9] The utilities also proposed the extension and expansion of the ELRP through 2027 in their recent DR applications (A.22-05-002, A.22-05-003, and A.22-05-004). In fact, Pacific Gas and Electric Company (PG&E) specifically proposed spending over 50%

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[6] *Id*. at 5-6.

[7] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

[8] Note that customer counts for Group B exclude B.1. (third-party DRPs). For more information, see Table 1-1, Active PY2022 ELRP Customer Enrollment Counts in the PG&E 2022 ELRP Load Impact Report (Draft), from March 10, 2023.

[9] *See* Decision (D.) 21-03-056 at 2, 20, COL6 at 80, OP7 at 85 (establishing the ELRP as "an insurance policy against the need for future rotating outages" and stating "ELRP should be viewed principally as an insurance policy made available during emergency conditions to supplement the reliability already provided by the RA program"); *see also* D.21-12-015, OP6 at 162 (Dec. 6, 2021).

of its DR budget for program years 2024-2027 on the ELRP ($425 Million).[10] The State and Commission's continued support of the ELRP demonstrates the value and performance of load-modifying DR programs in reducing energy demand during times of grid stress.

While CAISO-market integrated programs are a valuable tool to reduce peak demand for some DRPs and/or customers, the State should not rely on those programs as its *only* programmatic solution to reduce peak demand in times of grid stress. In the 2022 Annual Report on Market Issues & Performance, CAISO's Department of Market Monitoring noted that a large portion of market integrated DR was not available for dispatch during key peak net load hours and states "the current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions."[11] Considering this, the Commission should seek to encourage, not limit, alternative DR program design. By expanding the definition of "qualifying DR program" for the purposes of the SGIP HPWH program, the Commission will encourage the growth of load-modifying DR programs that complement CAISO market-integrated DR programs and thereby more comprehensively ensure grid reliability. The Joint CCAs note that in D.22-04-036, Finding of Fact 64 states: "It is reasonable to adopt guidance that will facilitate expansion of demand response offerings for customers installing HPWH."[12] By expanding the definition of "qualifying DR program[,]" consistent with Energy Solutions' recommendation discussed above, the Commission will not only allow customers the flexibility to enroll in a broader range of existing demand management programs that deliver load reductions, but also facilitate the expansion of beneficial load-modifying DR programs, offered by a spectrum

[10] *See* A.22-05-002 et al., Application of Pacific Gas and Electric Company (U 39 E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 at 21 (May 2, 2022).
[11] http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf, p. 24.
[12] D.22-04-036 at Finding of Fact 64.

of load serving entities. Ultimately, this will help ensure that customers installing HPWH have the flexibility to benefit the grid through a variety of strong program options.

MCE's Peak FLEXmarket program, for example, is a load-modifying DR program that combines both daily load-shift and event-based incentives under one program umbrella. The program demonstrated great success in reducing peak demand and supporting grid reliability during last year's September heatwave. During the 11 consecutive event days, the program achieved more than 39,000 kWhs in energy savings with almost 2,200 participating resources. The program achieved an additional 30,000 kWhs in energy savings from daily load shifting during the summer month, which is equivalent to taking about 300 residential customers off the grid during peak hours. MCE's Peak FLEXmarket program clearly demonstrates that non-CAISO market-integrated programs can provide essential peak demand reductions during times of peak demand.

The importance of daily load-shifting programs, above and beyond event-based programs, cannot be overstated. Encouraging customers to shift load out of peak times daily does not only lead to true behavior changes in customers, but also delivers significant grid and environmental benefits by mitigating the duck curve on a daily basis. Customers who have experience with shifting load out of peak times on a daily basis are likely to be more engaged and knowledgeable about their electricity use. Customers' knowledge and engagement translates to beneficial behavior changes during times of grid stress (i.e., event days). Hence, daily load-shifting programs can be an important asset in the "toolbox" of demand management programs that reduce demand during peak times.

II. CONCLUSION

The Joint CCAs appreciate the opportunity to provide these reply comments on the July ACR. The Joint CCAs continue recommending the Commission update the definition of a "qualifying DR program" to include both CAISO market-integrated and load-modifying programs; event-based and daily load-shifting programs; and IOU-administered and non-IOU-administered (CCA and third party DRP) programs.

Respectfully submitted,

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On behalf of Joint Community Choice Aggregators

Dated: August 11, 2023

California Community Choice Association

SUBMITTED 08/14/2023, 01:54 PM

Contact
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1. Please provide a summary of your organization's comments on the Extended Day-Ahead Market (EDAM) ISO Balancing Authority Area (BAA) Participation Rules track A1 draft final proposal, and Aug 2, 2023 stakeholder call discussion:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the EDAM ISO BAA Participation Rules Track A1 Draft Final Proposal (Draft Final Proposal) and August 2, 2023 stakeholder call. In summary, CalCCA recommends:

- The ISO should adopt its proposals to always keep the net export transfer constraint on, distinguish between stressed and non-stressed hours for the confidence factor and reliability margin, and memorialize other details in the Business Practice Manual (BPM);
- Adopt the ISO's proposal to initially use a confidence factor of zero during non-stressed and stressed system conditions;
- Transmission revenue recovery and Wheeling Access Charge (WAC) revenues should be a transitional mechanism only, accompanied by a sunset date such that the proposal does not introduce indefinite uplift payments and market inefficiencies;
- The ISO should adopt its proposal to allocate Resource Sufficiency Evaluation (RSE) failure surcharges and revenues on an hourly basis based on megawatt (MW) of metered demand for each Scheduling Coordinator (SC) as a portion of total ISO BAA metered demand; and
- A long-term solution for allocating RSE failure surcharges and revenues will need to deviate from the stakeholder-proposed two-tier allocation methodology in order to accurately capture cost causation.

2. Provide your organization's comments on the proposed EDAM ISO BAA Participation Rules initiative tracks and schedule:

CalCCA supports the proposed EDAM ISO BAA Participation Rules tracks and schedule.

3. Provide your organization's comments on the Track A1 draft final proposal: Criteria to Set the ISO BAA's Net EDAM Export Transfer Constraint:

The ISO should adopt its proposals to keep the constraint on at all times, distinguish between stressed and non-stressed hours for the confidence factor and reliability margin, and memorialize other details in the Business Practice Manual (BPM). Memorializing the details in the BPM will allow the ISO to adjust the confidence factor levels, reliability margin levels, and definitions of stressed and non-stressed conditions as the ISO and ISO BAA participants gain experience with EDAM. CalCCA supports the revised definition of stressed hours to include net peak hours. The ISO indicates net peak hours automatic triggering of stressed conditions will be applied on a seasonal basis with additional details to be determined in the BPM process. When determining which seasons to use net peak hours as stressed conditions, the ISO should present an analysis in the BPM process to support any findings that suggest net peak hours are not stressed during certain seasons.

While CalCCA originally supported the ISO basing the confidence factor during non-stressed conditions based on historical delivery of non-RSE eligible supply, CalCCA supports the ISO's proposal to use a confidence factor of zero during non-stressed and stressed system conditions. This approach allows the ISO to start conservatively and revise the confidence factors in the BPM process as it gains experience in EDAM. It may be that as the ISO gains this experience, the ISO and ISO BAA participants can become more comfortable with raising the confidence factor during non-stressed system conditions to be more consistent with historical delivery of non-RSE eligible supply.

4. Provide your organization's comments on the Track A1 draft final proposal: Transfer Resource Settlement and Transfer Revenue Distribution:

CalCCA has no comments at this time.

5. Provide your organization's comments on the Track A1 draft final proposal: Process for Recovering Historical Wheeling Access Charge Revenues:

The ISO proposes a process for determining the recoverable foregone historical WAC revenues, including revenues associated with reduction in WAC revenues at existing transfer locations; unrealized WAC revenues attributed to non-firm use of approved new transmission builds that increase transfer capability between EDAM BAAs; and revenues for wheeling-through transfer volumes for EDAM BAAs that exceed the total imports/export transfers from the EDAM BAA.

CalCCA continues to hold its position from the EDAM stakeholder process and previous comments. That is, while making transmission available to the EDAM on a hurdle-free basis may result in a reduction in transmission revenue and WAC revenues relative to historical revenues, transmission revenue recovery and WAC revenues should be a transitional mechanism only, accompanied by a sunset date such that the proposal does not introduce indefinite uplift payments and market inefficiencies.[1]

The ISO states in the Draft Final Proposal that "in the Extended Day Ahead market, the ISO committed to review this mechanism provision in a future initiative, as the ISO gains experience with EDAM."[2] This review should result in a commitment to sunset the historical transmission revenue recovery mechanism on a reasonable timeframe after EDAM implementation.

[1] CalCCA Comments on the Issue Paper and Track A Straw Proposal (May 17, 2023): https://stakeholdercenter.caiso.com/Comments/AllComments/f4f5607b-8a10-4fc7-b065-eca237f20800.

[2] *Extended Day-Ahead Market ISO Balancing Authority Area Participation Rules Track A1 Draft Final Proposal* (July 25, 2023), at 19: http://www.caiso.com/InitiativeDocuments/TrackA1DraftFinalProposal-EDAMISOBAAParticipationRules.pdf.

6. Provide your organization's comments on the Track A1 draft final proposal: Interim Solution for Allocating RSE Failure Surcharges and Revenues:

The ISO should adopt its proposal to allocate RSE failure surcharges and revenues on an hourly basis based on MW of metered demand for each SC as a portion of total ISO BAA metered demand. While CalCCA supports the allocation of costs on a cost-causation basis consistent with the principles put forth by the ISO,[1] it will take time to develop and implement an approach that accurately allocates costs to market participants that caused the RSE failure. The ISO should adopt its interim proposal for Track A1 and consider in the next track if and how to modify the approach for the long term.

[1] CAISO Presentation: Extended Day-Ahead Market ISO Balancing Authority Area Participation Rules, Stakeholder Workshop on Track A1 (June 14, 2023), at Slide 21: http://www.caiso.com/InitiativeDocuments/Presentation-ExtendedDay-AheadMarketISOBAAParticipationRules-Jun14-2023.pdf.

7. Please also provide your organization's ideas for a Long-Term Solution for Allocating RSE Failure Surcharges and Revenues (which will be developed in Track B). More specifically, please provide your organization's comments on the stakeholder-proposed two-tier allocation methodology (see footnote 21 on page 31 of the draft final proposal) and/or please provide suggestions for the parameters that should be considered in a long-term solution:

The ISO indicates that it will use the two-tier approach proposed by Pacific Gas and Electric Company, San Diego Gas & Electric, Six Cities, and BAMx (Joint Parties) in their June 28, 2023 comments as the starting point for the long-term cost allocation solution. Under that approach, in the first tier, surcharges are allocated to Load-Serving Entities (LSEs) whose month-ahead supply portfolios (RA + Non-RA) are less than their daily peak LSE metered demand. In the second tier, surcharges are allocated pro-rata to LSE-metered demand. The Joint Parties put forth this proposal as an interim approach intended to be implemented in Track A1. A long-term solution, however, will need to deviate from this proposal in order to accurately capture cost causation.

The ISO and stakeholders should consider the following factors when developing a long-term solution:

- The ISO and stakeholders should start by identifying the many factors that drive RSE failures or surpluses (including contracts for Resource Adequacy (RA) and non-RA supply, RA and non-RA generators on outage, the availability of substitute capacity not shown). Approaches that target just one of the many causes of RSE failure could *worsen* cost causation relative to a metered demand approach. Therefore, conducting cost allocation based upon only some of the possible drivers of an RSE failure just because those drivers are easier to identify than the others is not just and reasonable.

- It could be extremely difficult to tie a resource's schedule to a particular LSE because there is not a one-for-one relationship between the schedule of a resource and the LSE for which it is serving. LSEs do not have to be the scheduling coordinator for their resources. Even where an LSE is the scheduling coordinator for a resource, there is no guarantee that the resource being scheduled is to serve that LSE's load. The LSE may have sold the output associated with that resource to another LSE. Resources may provide partial capacity or capacity to multiple different LSEs, making it difficult to determine which portion of the capacity ties to which LSE. The only way to realistically allocate charges based on metered demand net of contracted supply may be to understand the contractual obligation between LSEs and resources. The schedule alone does not provide this information.
- RA requirements and RSE requirements are not identical and serve different purposes. Any allocation methodology for RSE failure deficiencies should not be duplicative of RA penalties and should instead target the specific RSE requirements the charges would be based upon. LSEs enter into many different types of contracts with RSE-eligible resources beyond RA-only contracts, including contracts for substitute capacity and contracts for hedges (e.g., firm-energy contracts, call options, etc.).

- There are RA program compliance mechanisms in place to incentivize CPUC and non-CPUC jurisdictional LSEs to bring enough supply to the market. The RSE failure consequences should avoid duplicative charges on LSEs who have already paid for their deficiencies through CPUC and ISO RA compliance mechanisms. The RA program incents upfront compliance through a robust penalty structure at the CPUC. LSEs face tiered penalties increasing in price based upon the number of deficiencies the LSEs have. The penalties for RA deficiencies at the CPUC start at $8.88 in the summer months and go up to three times that amount for repeat deficiencies. LSEs also face reputational risk with being on the RA penalty list. Some LSEs also face limits on expansions if they do not meet their RA requirements.[1] If LSEs are short on their RA requirements, in addition to paying the CPUC penalties, the ISO can backstop through its CPM to fill the deficiency and allocate costs first to deficient LSEs. Therefore, LSEs will either (1) collectively meet their RA obligations, obviating the need for ISO backstop, or (2) receive costs of ISO backstop allocated to them if they are the cause of a deficiency. After ISO backstop for RA deficiencies occurs, LSEs' obligations to bring supply to the day-ahead market are fulfilled, and it is up to the supplier to ensure the resource is available and offered into the day-ahead market consistent with its must-offer obligation to pass the RSE. In short, the mechanism for an RA compliance failure is for the ISO to backstop procure. If it does, then the reason for an RSE failure is not the RA deficiency because the ISO backstopped it. If the ISO does not backstop, then the ISO has determined that it has sufficient RA collectively and once again, the cause of the RSE failure cannot be said to have been caused by an RA deficiency since the ISO determined that collectively, no such deficiency existed.

- If it is not possible to determine cost causation, there is precedent for the ISO allocating costs to metered demand – significant event and exceptional dispatch CPM costs are allocated in this manner.

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[1] California Public Utilities Commission, Decision 23-06-029, *Decision Adopting Local Capacity Obligations for 2024 - 2026, Flexible Capacity Obligations For 2024, and Program Refinements, Rulemaking 21-10-002* (July 5, 2023)*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF*.

8. Provide any additional comments on the EDAM ISO BAA Participation Rules track A1 draft final proposal, and Aug 2, 2023 stakeholder call discussion:

CalCCA has no additional comments at this time.

California Community Choice Association

SUBMITTED 08/15/2023, 03:41 PM

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1. Of all of the concepts and proposals presented in the Discussion Document and in working groups, what concepts or proposals do you think will be most meaningful in addressing the problem statements?

1) Interconnection request intake, 2) Queue management

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the thoughtful and innovative proposals put forth by stakeholders in the Interconnection Process Enhancements (IPE) 2023 Track 2 working groups. CalCCA recognizes that the direction of the initiative will be impacted by the Federal Energy Regulatory Commission (FERC) Order 2023. As with the August 1, 2023 workshop and as directed by the California Independent System Operator (ISO), CalCCA focuses its comments on stakeholder proposals without attempting to conclude whether or not such proposals will be compliant with the FERC Order 2023. Making those conclusions will be an important next step in the process.

In summary, CalCCA makes the following recommendations:

- Data transparency and accessibility is an essential first step towards tightening the link between resource and transmission planning, procurement, and interconnection. The ISO should publicize the data points listed by the ISO in its August 1, 2023 presentation and the data points proposed by The AES Corporation (AES) in its Annual Interconnection Overview Report presented at the July 11, 2023 working group;
- If the ISO moves forward with its Concept 1 (a transmission zone-based or queue-wide constraint for accepting interconnection applications or studying select interconnection requests), CalCCA supports using AES' proposed scoring point system as a starting point for developing a prioritization methodology;
- CalCCA supports the proposal put forth in Sonoma Clean Power's (SCP's) comments in Section 3, which outlines an election process that mimics the Remaining Import Capability (RIC) election process, where load-serving entities' (LSEs') influence is calibrated to load share;
- AES' proposed "Resource Diversity" criteria should give points to high-capacity factor resources and long-lead time development resources;
- The ISO should analyze the magnitude, locations, and durations of deliverability shortages flagged by stakeholders. Based on these findings, the ISO should then explore with the California Public Utilities Commission (CPUC) opportunities to improve the deliverability retention process and interim deliverability process to mitigate the potential impacts of lengthy transmission upgrades and network upgrades on project Commercial Operation Dates (CODs);
- CalCCA supports the ISO exercising its ability to remove projects from the queue if they cannot demonstrate progress toward development milestones;
- The ISO should further evaluate the process improvement proposals made by the IOUs and adopt them if they will ensure meaningful study results, increase process effectiveness, and reduce time and staff requirements;

- Using 1.5 as the overall ratio of total capacity to total need is likely too low to ensure competition among developers competing for contracts with LSEs. The ISO should study as much capacity as maintains the usefulness of the study results, but at least two to three times the available and planned transmission capacity;
- If the ISO increases study deposits, it should do so scaled based on project size to ensure study deposits are not a barrier to smaller developers and smaller projects; and
- The ISO should not pursue an auction mechanism. Other mechanisms, like those outlined in Section 1 below, should be used to determine which projects are most commercially ready.

Transparency:

Data transparency and accessibility is an essential first step towards tightening the link between resource and transmission planning, procurement, and interconnection. CalCCA supports regular reporting of information necessary for developers to make informed interconnection requests and for LSEs to use when they are evaluating prospective projects. Improving the availability and accessibility of available existing and planned interconnection capacity, transmission plan deliverability (TPD) allocations, upgrade costs, and other public queue data as early and often as feasible will reduce the amount of speculative interconnection requests submitted. Interconnection customers will not need to use the interconnection study process to gain information, as they will already have the information available to them necessary to align resource development with existing and planned transmission capacity.

The ISO should publicize the data points listed by the ISO in its August 1, 2023 presentation[1] and the data points proposed by AES in its Annual Interconnection Overview Report presented at the July 11, 2023 working group.[2] Middle River Power's suggestion for a graphical user interface that publishes the amount of interconnection capacity available at points of interconnection in the ISO could be used to make this information easily accessible to interconnection customers and LSEs.[3]

Scoring Criteria:

If the ISO moves forward with its Concept 1 (a transmission zone-based or queue-wide constraint for accepting interconnection applications or studying select interconnection requests), CalCCA supports using AES's proposed scoring point system as a starting point for developing a prioritization methodology.[4] It largely reflects the type of criteria LSEs use to evaluate potential resources to contract with.

AES's scoring point system should be enhanced in two ways. *First*, determine how commercial readiness points are assigned through direct LSE input rather than PPA status. PPAs are typically signed after the interconnection agreement and full capacity deliverability status (FCDS) allocation for the reasons described in the deliverability section below. LSE interest through the assignment of points is more appropriate, especially if there is uncertainty around deliverability status, network upgrade costs, and network upgrade timelines at the time of point assignment. Therefore, commercial readiness points should be informed by LSEs assigning points to projects they are interested in. LSE interest would be informed by their own IRPs and preferences for technologies and locations. CalCCA supports the proposal put forth in SCP's comments in section 3, which outlines an election process that mimics the RIC election process, where LSE's influence is calibrated to load share. SCP's proposal recognizes that given the importance of deliverability, which may not be certain at the time of scoring, the best way to gauge contractability is to directly ask the LSEs rather than require demonstrations of PPAs.

Second, AES' proposed "resource diversity" criteria would provide additional points to resources that achieve specific resource diversity goals of the state or meet other criteria. The resource diversity criteria should include points for high-capacity factor resources and long-lead time development resources that are necessary to meet decarbonization goals but will also take longer to develop after going through the interconnection study process.

Additionally, CalCCA generally supports New Leaf Energy's proposal to prioritize projects in local areas,[5] as it will assist in CCAs developing projects in their own communities and near load centers. However, in adopting this proposal, the ISO must recognize there are two ways to address local reliability needs: new resources in the local area and new transmission to relieve local area constraints. An assessment of the costs and feasibility of both solutions must be performed before assigning points to ensure the best alternatives are known in advance of pursuing one over the other.

Whether or not the ISO moves forward with scoring criteria to prioritize interconnection applications or studies, the TPD allocation process should be updated to align with the scoring criteria developed here, including using LSE interest rather than or in addition to the PPA requirement.

Deliverability:

Deliverability allocations are key indicators CCAs use to determine which projects to pursue PPAs with. Until they have certainty of a resource's deliverability status, CCAs are largely unwilling to move forward with PPAs given the associated risk in doing so. CCAs require certainty around projects' deliverability statuses because deliverability is required to count projects towards their IRP procurement orders and resource adequacy (RA) requirements. The ISO should pursue proposals that allow for upfront certainty of projects' deliverability status, or network upgrade costs and timelines to obtain FCDS, to allow projects to remain viable and accelerate their development.

Several stakeholders, including Clearway and LSA,[6] flagged that they anticipate a mid-term (2028-2030) gap in available deliverability to allocate to Cluster 14 projects driven by the amount of time it will take for upgrades to be completed. Because deliverability certainty is necessary for LSEs to move forward in the contracting process, this gap may result in projects exiting the queue until upgrades are complete, slowing down the much-needed deployment of new resources and creating additional strain on the already overwhelmed interconnection queue.

To address this issue, the ISO should first analyze the magnitude, locations, and durations of deliverability shortages. Based on these findings, the ISO should then explore with the CPUC opportunities to improve the deliverability retention process and interim deliverability process to mitigate the potential impacts of lengthy transmission upgrades and network upgrades on project CODs. Coordination with the CPUC is critical to ensure future procurement orders are designed so that LSEs and developers can be successful in bringing new resources online in compliance with the orders.

Enforcing Required Milestones:

Per the Generator Management Business Practice Manual Section 6.5.2.1, projects studied in the cluster study process must have CODs that do not exceed seven years from the date the Interconnection Request is received by the ISO. A cluster-study project seeking to remain in the queue beyond seven years must clearly demonstrate why it will take longer and that the circumstances for delay were beyond the control of the interconnection customer. Projects seeking deliverability must also demonstrate viability criteria.

Stakeholders point out that despite these requirements, there are many projects that remain in the queue beyond their planned CODs and beyond the seven-year threshold.[7] Some also ask questions about the ISO's enforcement efforts for this rule[8] or recommend modifications to this process to penalize or remove projects from the queue after seven years if the project cannot demonstrate that it is meeting development milestones.[9]

CalCCA supports the ISO exercising its ability to remove projects from the queue if they cannot demonstrate progress toward development milestones. The milestones and timelines for removal will likely be dependent on technology. A full seven years from interconnection request and COD will likely be unnecessary for "first ready" projects that are not long-lead time, while long-lead time projects like geothermal and offshore wind will likely require more time between entering the queue and reaching COD. CalCCA supports the ISO ensuring projects are on track, and removing those that are not making progress, while recognizing the differences in technology and factors outside the control of the developer.

Study Process Improvements:

The IOUs propose several process improvements that would simplify the interconnection study process and reduce the required time and resources to complete study process. These process improvements would include simplifying the application package, using generic study inputs and/or past study results, and providing cost estimates/timelines using generic study results/past study results.[10] The ISO should further evaluate these proposals and adopt them if they will ensure meaningful study results, increase process effectiveness, and reduce time and staff requirements.

While simplifying the study process should remain the ISO's primary focus in IPE, the ISO should also explore its ability to leverage automation and advancements in new technologies as suggested by stakeholders to determine if such measures can be used to speed up the existing study process.[11]

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[1] 2023 Interconnection Process Enhancements Track 2 Working Group (Aug. 1, 2023) at 21: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-Track-2-Aug12023.pdf.

[2] AES Interconnection Intake Proposal (July 11, 2023) at 41-42: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[3] Middle River Power CAISO IPE 2023 Phase 2 Proposals (July 11, 2023) at 112-113: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[4] AES Interconnection Intake Proposal (July 11, 2023) at 43-44: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[5] New Leaf Energy, Prioritizing Local RA (July 11, 2023) at 52: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[6] Clearway Energy Group, Proposals: Interconnection Process Enhancements 2023 and LSA, 2023 IPE LSA Recommendations (July 11, 2023): http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[7] Vistra, Interconnection Process Enhancements 2023 Working Group Meeting #3 (July 11, 2023) at 100: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf; and, Gridwell Consulting, IPE 2023 Working Group 4 Proposals (July 24, 2023) at 47: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-Track2-Working-Group-Jul242023.pdf.

[8] LSA, 2023 IPE, Track 2 LSA Recommendations: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-Track2-Working-Group-Jul242023.pdf.

[9] Vistra, Interconnection Process Enhancements 2023 Working Group Meeting #3 (July 11, 2023) at 101: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf

[10] SDG&E IPE Proposal Summary at 119, SCE Proposal for Working Group Session 3 at 125-127, PG&E 2023 IPE Proposal (July 11, 2023): http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

[11] NextEra, 2023 Interconnection Process Enhancements at 70: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track%202-Working-Group-Jul112023.pdf.

2. Of all of the concepts and proposals presented in the Discussion Document and in working groups, what concepts or proposals concern you? Please describe how these concepts fail to adhere to the principles or would not appropriately address the problem statements.

1) Interconnection request intake, 2) Queue management

Restricting Competition

CalCCA cautions the ISO against proposals that restrict competition among developers competing for contracts with LSEs procuring new resources to meet procurement mandates and climate goals. If the ISO implements a transmission zone-based approach that limits the amount of interconnection requests based upon existing and planned transmission capacity, the ISO must ensure sufficient interconnection capacity is studied to maintain competition among developers.

Studying capacity up to 1.5X the available and planned transmission capacity is too limiting. The ISO plans the transmission system based on resource portfolios the CPUC projects will be needed to support reliability and policy goals. LSEs will ultimately need to procure capacity consistent with those plans. If the ISO only studies 1.5X the amount of capacity needed to support reliability and policy goals, LSEs would experience significantly reduced bids in their request for offers (RFOs) relative to their procurement needs. Past experience also shows that many projects do not ultimately proceed in the development process and may drop out after it submits its interconnection request but before the contracting process. While some projects may offer to multiple LSEs, multiple LSEs may have interest in the same project, too.

Using 1.5 as the overall ratio of total capacity to total need is likely too low to ensure competition among developers competing for contracts with LSEs. The ISO should study as much capacity as maintains the usefulness of the study results, but at least two to three times the available and planned transmission capacity.

CalCCA also cautions against increasing study deposits too much such that they favor larger developers and crowd out the smaller developers. If the ISO does increase study deposits, it should do so scaled based on project size to ensure study deposits are not a barrier to smaller developers and smaller projects.

Auction

The ISO indicates an auction could be used as a secondary step if necessary to further narrow down projects to study to some percentage above TPD per zone.[1] CalCCA recommends the ISO pursue other mechanisms, like those outlined in section 1 above, for determining which projects are most commercially ready. CalCCA is concerned that an auction would:

1. Result in increased costs to ratepayers because the costs associated with bidding into the auction will ultimately flow to them;
2. Result in the highest bidders being studied rather than the most ready being studied;
3. Incent speculative projects to enter the queue by creating a secondary market where those projects can sell their queue position later;
4. Limit competition among developers by favoring larger developers with deeper pockets over small developers.

[1] 2023 Interconnection Process Enhancements Track 2 Working Group (Aug. 1, 2023) at 21: http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-Track-2-Aug12023.pdf.

3. Please provide any suggested modifications to combinations of the proposed concepts, or additional thoughts to meet the principles established for the initiaitve:

1) Interconnection request intake, 2) Queue management

CalCCA has no additional comments at this time.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 23-05-012

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO ALJ ORDER REGARDING FIXED GENERATION COSTS

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August 16, 2023

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SUMMARY OF RECOMMENDATIONS

- Resolution of the issues raised in the Administrative Law Judge's August 1, 2023, ruling requires a clear definition of the term "Fixed Generation Costs" that is analyzed and considered consistently across the three IOU service territories.

- A consolidated Phase II of this proceeding will ensure the Commission can develop the record necessary to ensure a reasonable and consistent resolution without violating the Commission's *de facto* prohibition on policymaking in the ERRA Forecast proceedings.

- If the Commission creates a consolidated Phase II, it should move what is currently Scoping Ruling Item 9(a) in this proceeding to Phase II to allow the Commission to address the "Fixed Generation Cost"-related issues simultaneously across service territories and avoid the prohibition on policymaking in the ERRA Forecast.

- Solutions beyond including "Fixed Generation Costs" in a new or existing nonbypassable charge should be included within scope in a consolidated Phase II.

- The Commission should target developing a record on this issue after the October Update and proposed decisions in the current phase of the ERRA Forecast proceedings have passed.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 23-05-012

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO ALJ ORDER REGARDING FIXED GENERATION COSTS

The California Community Choice Association[1] (CalCCA) hereby submit these comments in response to Administrative Law Judge Long's August 1, 2023 Ruling (ALJ Ruling),[2] regarding the "Fixed Generation Costs" within the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* submitted on May 15, 2023 (Application).

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy (EBCE), Energy for Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Application ("A.") 23-05-012, *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (May 15, 2023) ("Application"), *Administrative Law Judge's Ruling Directing Parties To Comment Regarding Fixed Generation Costs*, p. 1 (August 1, 2023) ("ALJ Ruling").

The ALJ Ruling causes a number of concerns for community choice aggregators (CCAs) and the departed customers they represent. Primary among them are (1) the ruling being construed as an invitation to include as many "Fixed Generation Costs" into a new or existing nonbypassable charge (NBC) as possible; and (2) the potential for re-litigating the Power Charge Indifference Adjustment (PCIA) Rulemaking (R.) 17-06-026 within an expedited ERRA forecast proceeding. The Commission should provide parties the litigation tools and timelines necessary to scrutinize the investor-owned utilities' (IOUs) responses to the questions the ALJ raises. The current timeline of PG&E's ERRA forecast proceeding does not meet this standard given the other issues with which the Commission must contend, and neither does the *one-week* timeline provided by the ALJ for parties to respond to the IOUs' opening comments.

Given the Commission's *de facto* prohibition on policymaking in the expedited ERRA cases, a second phase of the instant proceedings is required. Ideally, that timeline provides for record development to take place after the storm of expedited discovery, comments and briefing surrounding the October Update and proposed decision has passed.

There simply is no urgent need that requires straining further the parties' and the Commission's resources to answer this question before rates are put in place on January 1, 2024. None of the three service territories, including PG&E's, is near the drastic and unrealistic hypothetical scenario of the "last bundled customer" the ALJ ruling references. There are already difficult issues in each case with which the Commission will need to contend, including a new Energy Index weighting methodology, how to value the potential use of banked RECs to meet bundled compliance obligations, a new proposal to amortize the residual balance in the PCIA Undercollection Balancing Account, and, as in every Forecast case, the critical issues of whether PG&E's forecasted sales and various revenue requirements and rates are correctly calculated, and in compliance with all applicable rules, regulations, resolutions and decisions. The new issues each IOU tends to raise in its October Update each year will only further tax parties' resources.

Adding to this existing burden, the ALJ Ruling raises a number of new issues:

- What is the appropriate definition of Fixed Generation Costs?
- Whether the IOUs' responses to the ALJ Ruling demonstrate a consistent definition of "Fixed Generation Costs" such that the same types of costs are included for each of PG&E, Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E);
- Whether the accounting procedures for each IOU would allow "Fixed Generation" costs to be shown separately from other generation costs and accounted for in a manner that may be different than current practices; if not, whether modifications to prior Commission decisions are needed to ensure consistent accounting treatment across IOUs; and
- At what threshold of remaining bundled customers should the Commission consider alternatives to cost recovery mechanisms for Fixed Generation Costs, including but not limited to the potential for utility divestment of UOG.

These issues should form the basis of an amended scoping ruling to be considered in a later, consolidated Phase II of this proceeding.

I. A REVISED SCOPING RULING SHOULD CREATE A SECOND PHASE TO CONSIDER THE ISSUES RAISED IN THE ALJ RULING.

A. Questions 1 and 2 Trigger a Number of Potential Scoping Issues for A Second Phase of this Proceeding.

The ALJ Ruling asks the parties to "1. Identify and briefly describe each category of Fixed Generation Costs in this proceeding;" and 2. Complete a table listing different costs, the balancing accounts used for tracking those costs, the estimated 2023 costs, and the "Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Customer."[3] The different costs include the following:

[3] ALJ Ruling at 1-2.

- Competitive Transmission Charge Contract Costs;[4]
- California Independent System Operator and North American Electric Reliability Corporation Costs;
- Hedging-Related Costs;
- Western Renewal Energy Generation Information System Costs;
- ERRA-related Cogeneration/Renewables Costs;
- Electric Supply Administration Costs;
- Replacement Resource Adequacy (RA) Costs; and
- Other Costs.

As noted in the ALJ Ruling,[5] CCAs typically do not have easy access to the data necessary to respond to Question 2, and the ruling left insufficient time for both discovery and the development of robust comments on the question.[6] However, the Assigned Commissioner's office might include an updated version of these two questions – and the additional questions they trigger – as scoping items in an amended scoping ruling for a future phase of this proceeding.

It is difficult to discern from the ALJ Ruling the type of costs the Commission envisions as being "Fixed Generation Costs." The ALJ Ruling defines the term as IOU "generation costs recovered through the Energy Resource Recovery Account (ERRA) Balancing Account that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation."[7] It also includes "debits transferred to the ERRA

4 It appears the ALJ Ruling misstated this category of costs. CalCCA assumes this is meant to be the "Competition Transition Charge" as we are not aware of a "Competitive Transmission Charge" that would be functionalized as generation and/or fall under the Commission's jurisdiction.

5 ALJ Ruling at 1, n. 2.

6 *Id*. at 1 (giving parties two weeks for opening comments in the context of a 10-business day discovery timeline).

7 *Id*.

Balancing Account from other regulatory accounts."[8] A scoping item for parties to consider in a future Phase II might be "What is the appropriate definition of Fixed Generation Costs?" in order to more clearly delineate what is being considered.

To wit, CalCCA finds the list of categories of "fixed" costs in the table comprising most of Question 2 odd. Nearly all of these categories of costs are already spread among all customers, with bundled customer departures leading to departed customers taking on more of the costs. To the extent there are any truly "fixed" electric generation costs, those costs flow through the PCIA for PCIA-portfolio resources (or other NBCs, like those for Cost Allocation Mechanism (CAM) resources, that apply to all customers), and are therefore recovered from bundled and unbundled customers as a matter of course. For example, if there were *zero* remaining bundled customers, the costs of PCIA-eligible utility-owned generation (UOG) – including fixed and variable costs – would be recovered through CAISO market revenues (the at-market costs) and PCIA rates (the costs that are above market or are tied to resource attributes that could not be sold).

Questions 1 and 2 within the ALJ Ruling create two key concerns. The first is whether the IOUs have a consistent definition of "Fixed Generation Costs" such that their respective responses to the ruling include the same types of costs for SDG&E and SCE as for PG&E. This concern of consistency across IOUs should form the basis of another issue in an amended scoping ruling for Phase II if the Commission chooses to go that route.

The second concern is whether the accounting procedures for each IOU would allow the IOUs to separate those fixed costs from other (variable) generation costs and account for them in a manner different than current practices. For example, PG&E clearly reports Electric Supply Administration (ESA) costs as a separate cost category when seeking approval of its revenue

8 *Id*. at 1, n. 1.

requirement in Phase I General Rate Cases, and it is not clear SCE and SDG&E can follow PG&E's practice without violating prior Commission decisions. Sufficient time and process should be afforded to answer these questions. However, even after that process unfolds, the Commission may need still need to modify prior decisions. Another scoping item for Phase II could ask whether the accounting procedures between utilities allow for alignment and, if not, whether such modifications to prior decisions are required.

Leaving space for other parties to propose alternatives to an NBC approach is also critical to ensure sufficient context and record development for the Commission to address the questions raised in the ALJ ruling. An important piece of context might include the pending resolution of two vintaging proposals in the PG&E and SDG&E Phase I General Rate Cases to ensure (1) there are no "forever PCIA assets" and (2) the IOUs cannot simply add costs to existing UOG to expand generation capacities or change basic functionality with the expectation that already departed load will continue to pay for those costs.[9] Adoption of these proposals could help control "Fixed Generation Costs" going forward, depending on the definition of that term the Commission ultimately adopts. Regardless of who ultimately pays for significant upgrades of UOG, the Commission should be wary of approving such upgrades when there is no evidence, they are needed to serve the IOUs current and expected bundled load. Without bundled load to serve, it makes little sense for IOUs to add to their generation costs by continually investing in UOG that is likely to be left stranded.

Moreover, the Commission may want to establish different thresholds to investigate different questions tied to this issue. None of the three service territories, including SDG&E's, is

[9] *See, e.g.,* A.21-06-021, Opening Brief of the Joint Community Choice Aggregators at Section 5, filed on November 4, 2022; A.22-05-016, Opening Brief of San Diego Community Power and Clean Energy Alliance at sections 18 and 19 (Aug. 14, 2023).

near the "last bundled customer" scenario the ALJ ruling lays out. Twenty percent of customers in SDG&E's service territory remain bundled customers, and the utility itself is forecasting that at least ten percent of its total load will remain bundled customers through 2024.[10] The Commission's own data for SDG&E's bundled customers forecasts 3,694 GWh of load in 2030, growing to 3,787 GWh in 2035.[11] That is, not even the Commission plans on SDG&E serving one lonely customer anytime soon. Even less urgent, 37% of customers in PG&E's service territory remain bundled customers, and 67% of customers in SCE's service territory remain bundled customers.

One threshold the Commission could establish is to determine a level of departed load to trigger a Commission investigation into whether an IOU should remain in the business of generating electricity as a public utility or, either, (1) be required to sell its UOG assets or (2) modify its business to spinoff the generation side to operate as an independent power producer. These questions should form a part of the conversation if the Commission is considering allowing the IOUs to retain rate-based generation assets in order to serve one bundled customer. This threshold-related scoping item could read: "At what threshold of remaining bundled customers should the Commission consider alternatives to cost recovery mechanisms for Fixed Generation Costs, including but not limited to the potential for utility divestment of UOG."

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[10] R.20-05-003, *2022 Individual Integrated Resource Plan of San Diego Gas & Electric Company (U 902 E)*, p. 96 (Nov. 1, 2022).

[11] The load forecast is available here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

B. Question 3: Adopting a Second Phase With an Extended Timeline Can Ensure the Scrutiny Necessary to Resolve the Issues Raised in the ALJ Ruling.

Question 3 asks:[12]

> *Should any issues associated with Fixed Generation Costs be addressed in this proceeding? If your answer is yes, briefly identify those issues and state whether those issues should be addressed with the other issues in this proceeding or in a separate phase after the other issues are addressed in a Commission decision.*

The issues associated with Fixed Generation Costs raised in the ALJ Ruling should only be addressed in a second phase of this proceeding. Those issues should include the suggested scoping items discussed in response to Questions 1 and 2, *supra*.

As the IOUs' applications state,[13] the limited purpose of the ERRA Forecast proceedings is to fulfill the IOUs' obligation under Pub. Util. Code Section 454.5(d)(3) to forecast generation rates for the following year based on forecasted load and forecasted balances in the ERRA and other balancing accounts established by prior Commission decisions. Those balancing accounts already include the Fixed Generation Costs referenced in the ALJ Ruling. The approval of cost recovery frameworks, the appropriate rate mechanisms to recover those costs, and the allocation of those costs among different customer vintages is pre-determined via authorizing Commission decisions in other proceedings and the utility's general rate case. The scope of ERRA forecasting

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[12] ALJ Ruling at 3.

[13] Application at 6-21; A.23-05-012, *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, pp. 6-22 (May 15, 2023); *but see* Application (A.) 23-06-001, *Application of Southern California Edison Company (U338E) for Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement*, pp. 1-2 and 7-8 (June 1, 2023) (relying on the Commission's general ratesetting authority in Cal. Pub. Utils. Code §454).

proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules or policies.[14]

The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[15] For example, the Scoping Memo in A.17-06-005 (PG&E's 2018 ERRA Forecast application) rejected the inclusion of certain CCA-proposed changes to the PCIA ratemaking methodology, stating:

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor-owned utilities and interested parties.[16]

Utilities rarely request modifications to cost recovery in the ERRA forecast proceeding that have not already been approved via a prior decision; but when they do, or when a policymaking issue needs to be addressed, it is the result of another Commission decision directing that issue be included in scope of the ERRA. This precedent can be seen in the ratemaking, policy and implementation work completed in ERRA forecast proceedings in the past few years, all of which stem directly from Commission decisions:

<u>For all three IOUs</u>:

- Implementation of changes to the methodology used to calculate the PCIA from D.18-10-019 and D.19-10-001;[17]
- Questions surrounding funding for the Solar on Multi-family Affordable Housing program;[18] and

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

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

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

[17] *See, e.g.,* D.18-10-019 at Ordering Paragraphs ("OPs") 8 and 10; D.19-10-001 at OPs 2-4.

[18] *See* D.17-12-022 at OP 4.

- Issues related to transparency and data access.[19]

For PG&E:

- The methodology to refund a CAM misallocation;[20]
- The methodology to return ERRA overcollections in an equitable manner;[21] and
- The methodology to calculate the RA component of GTSR rates.[22]

For SDG&E:

- The right billing determinants to reflect departing load when setting 2021 rates;[23] and
- Questions regarding the correct rate to form the basis for the PCIA rate cap.[24]

This proceeding itself will continue to consider policymaking from recent decisions. Recent RA decisions introduce accounting issues to the 2024 ERRA forecast proceedings. These issues include consideration of whether existing resources are procured by the Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028), or to meet the incremental procurement targets for 2021-2023 (D.19-11-016), and if they are accounted for correctly in the applicable CAM balancing account, Modified CAM memorandum account, and the Portfolio Allocation Balancing Account. Consideration of all of these policy issues in ERRA forecast proceedings hinges on prior Commission decisions. There is simply no "bandwidth" to consider issues related to the Fixed Generation Costs issues raised in the ALJ Ruling within the narrow scope and typical timeline of an expedited ERRA Forecast proceeding.

While policymaking is prohibited in a typical ERRA on account of those timelines, CalCCA recognizes it makes little sense for the Commission to issue an Order Instituting Rulemaking (OIR)

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19 D.20-12-035 at OP 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.

20 D.20-02-047 at 10.

21 *Id*. at 11-12.

22 D.20-12-038 at 28-29.

23 D.21-01-017 at 42-44.

24 *Id*. at 34-38.

in order to address issues tied to the ALJ Ruling. A second phase of the on-going ERRA Forecast proceedings can balance the prohibition against policymaking in expedited ERRA forecast cases while avoiding the unnecessary burdens of the Commission initiating what could be a single-issue OIR.

The impetus of the ALJ Ruling may be the proposal from PG&E to change its approved methodology for allocating ESA costs, and allocate those costs based on gross generation authorized costs as opposed to allocation on net authorized revenue requirements. If the Commission creates a consolidated Phase II, it should move the ESA issue, which is currently Scoping Ruling Item 9(a), in this proceeding to Phase II in order to avoid the prohibition on policymaking in the ERRA Forecast cases and allow the Commission to address the Fixed Generation Costs issue simultaneously across all three service territories.[25]

Comments received in response to the ALJ Ruling can reveal the level of parties' understanding of what are considered Fixed Generation Costs, the consistency of those views, and the degree of controversy they stir. Those factors can inform a prehearing conference and, eventually, the timelines, procedural mechanisms and litigation tools to be included in an amended scoping ruling for a second phase of the proceedings. That schedule should target the development of a record after the storm of the October Update and proposed decisions in the first phase of the cases has passed to avoid overwhelming party and Commission resources.

C. Question 4: Consolidation Makes Sense to Resolve the Issue Raised in the ALJ Ruling in a Consistent Manner Across IOU Service Territories.

Question 4 asks:

> *Should the three 2024 ERRA Forecast proceedings be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs? Please explain your answer and, if your answer is yes, state when the consolidation should occur.*

[25] Scoping Ruling at 3-4.

The three 2024 ERRA Forecast proceedings should be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs. As the IOUs have argued previously, dockets like rulemakings and consolidated applications apply to all California utilities and are noticed to, and generally include as parties, a broader set of stakeholders.[26] Consolidation also will ensure an efficient approach, preserving parties and the Commission's resources. The ALJ Ruling, which appears to be reproduced verbatim in three different proceedings, and these CCA-sponsored comments, which have been reproduced in all three proceedings with case-specific modifications, are evidence of the benefits of such an approach. Surely the administrative burdens of all parties and the Commission will be reduced by only having to analyze one set of pleadings and rulings as opposed to three as the Commission builds its decision-making record.

II. CONCLUSION

For the foregoing reasons, CalCCA respectfully requests the Commission initiate a consolidated Phase II of this proceeding, with timelines beginning in December, to consider:

- What is the appropriate definition of Fixed Generation Costs?
- Whether the IOUs' responses to the ALJ Ruling demonstrate a consistent definition of "Fixed Generation Costs" such that the same types of costs are included for each of SDG&E, SCE and PG&E;
- Whether the accounting procedures for each IOU would allow "Fixed Generation" costs to be shown separately from other generation costs and accounted for in a manner that may be different than current practices; if not, whether modifications to prior Commission decisions are needed to ensure consistent accounting treatment across IOUs; and
- At what threshold of remaining bundled customers should the Commission consider alternatives to cost recovery mechanisms for Fixed Generation Costs, including but not limited to the potential for utility divestment of UOG.

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

CalCCA appreciates the opportunity to submit these opening comments and look forward to continuing the discussion in reply comments.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 23-05-012

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO ALJ RULING REGARDING FIXED GENERATION COSTS

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SUMMARY OF RECOMMENDATIONS

- The Commission should initiate a Phase II of each IOU's ERRA Forecast proceeding, and consolidate those phases, in order to ensure the Commission can develop the record necessary to ensure a reasonable and consistent resolution of the issues triggered by the ALJ Ruling without violating the Commission's *de facto* prohibition on policymaking in the ERRA Forecast proceedings.

- The Commission should initiate a consolidated Phase II after the October Update and proposed decisions in the current phase of each IOU's ERRA Forecast proceeding has passed.

- The Commission should not consider PG&E's proposed modification to the methodology it uses to allocate Collateral Costs in the current phase of this proceeding. If the Commission creates a consolidated Phase II, it should consider PG&E's proposal in Phase II.

- If the Commission creates a consolidated Phase II, it should move what is currently Scoping Ruling Item 9(a) in this proceeding to Phase II to allow the Commission to address "Fixed Generation Cost"-related issues simultaneously across service territories and avoid the prohibition on policymaking in the ERRA Forecast.

- If the Commission creates a consolidated Phase II, it should not consider PG&E's Replacement RA Costs in that phase because PG&E's current approach is a settled issue recently litigated in the utility's 2019 ERRA Compliance proceeding.

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The California Community Choice Association[1] (CalCCA) hereby submits these reply comments in response to Administrative Law Judge Long's August 1, 2023 Ruling (ALJ Ruling),[2] regarding the "Fixed Generation Costs" within the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* submitted on May 15, 2023 (Application).

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy (EBCE), Energy for Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Application ("A.") 23-05-012, *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (May 15, 2023) ("Application"); A.23-05-012, *Administrative Law Judge's Ruling Directing Parties To Comment Regarding Fixed Generation Costs* (Aug. 1, 2023) ("ALJ Ruling").

The investor-owned utilities' (IOUs) opening comments on the ALJ Ruling (issued in each of the three IOUs' pending ERRA Forecast proceedings) validate CalCCA's concerns. Among those concerns, CalCCA anticipated that each IOU defines and records "Fixed Generation Costs" differently.[3] CalCCA also anticipated the IOUs might interpret the ALJ Ruling as an invitation to include as many "Fixed Generation Costs" as possible in new or existing nonbypassable charges.[4] Finally, CalCCA anticipated the IOUs already spread a significant portion of their "Fixed Generation Costs" across bundled and unbundled customers, rendering any discussion of the "Fixed Generation Costs" borne by a hypothetical "Last Remaining Bundled Customer" a distraction from the substantial work to be done in the IOUs' expedited ERRA Forecast proceedings.[5]

The IOUs' opening comments demonstrate the three IOUs indeed define or record "Fixed Generation Costs" inconsistently,[6] as CalCCA and the Public Advocates Office[7] (Cal Advocates) anticipated. And while the IOUs indeed provided a long list of costs in their respective responses to Question 2, the IOUs recover the bulk of those cost categories from all customers—unbundled

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3 A.23-05-012, *Comments of California Community Choice Association in Response to ALJ Order Regarding Fixed Generation Costs* at 5-6 (Aug. 16, 2023) (CalCCA Opening Comments).

4 *Id*. at 2.

5 *Id*. at 5.

6 A.23-05-012, *Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (PG&E Opening Comments); A.23-06-001, *Opening Comments of Southern California Edison Company (U 338 E) to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (SCE Opening Comments) (included as Attachment A to these reply comments); A.23-05-013, *San Diego Gas & Electric Company's (U 902 E) Opening Comments on Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 1 (Aug. 16, 2023) (SDG&E Opening Comments) (included as Attachment B to these reply comments).

7 *See* A.23-05-012, *Public Advocates Office (Cal Advocates) Comments on the Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* at 4 (Aug. 16, 2023) (observing that each IOU "appeared to define "fixed costs" differently" in response to a set of data requests issued in a previous proceeding); *see also* Cal Advocates' parallel comments in A.23-06-001 (SCE 2024 ERRA Forecast proceeding) and A.23-05-013 (SDG&E 2024 ERRA Forecast proceeding).

and bundled—through existing cost recovery mechanisms. As Southern California Edison (SCE) correctly notes:

> [T]he establishment of cost recovery mechanisms [that] allocate costs across both bundled service and departing load customers, such as the [Portfolio Allocation Balancing Account or PABA] with its vintaged cost recovery, greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend). This is because the departing load customers would continue to pay their cost responsibility through the [Power Charge Indifference Adjustment or PCIA] and [Competition Transition Charge or CTC] for PABA, and other rates that broadly allocate procurement cost, such as [Cost Allocation Mechanism or CAM] for [New System Generation Balancing Account or NSGBA], including Fixed Generation Costs recovered through the operation of these SCE Balancing Accounts.[8]

Overall, the IOUs' opening comments confirm a thorough and comprehensive evaluation of the issues triggered by the ALJ Ruling (1) requires further record development, and (2) lacks urgency. Indeed, of the three IOUs, only PG&E proposes to address any issue related to the ALJ Ruling in the current phase of its ERRA Forecast proceeding. Even SCE describes the "last bundled customer" scenario as "extreme and highly improbable."[9] The Commission should therefore adopt CalCCA's recommendations and initiate a consolidated Phase II to address the issues triggered by the ALJ Ruling once the current phase of the IOUs' 2024 ERRA Forecast proceedings is complete.

The Commission should reject PG&E's attempt to wedge a new issue into this phase of its ERRA Forecast proceeding. PG&E states it allocates two common cost categories—Energy Supply Administration (ESA) Costs and Collateral Costs—to multiple balancing accounts based on the prior year's adopted forecast **net** revenue requirements for those accounts, and now

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8 SCE Opening Comments at 5.

9 *Id*.

proposes to allocate those cost categories based on gross revenue requirements.[10] PG&E did not propose any change to its Collateral Cost allocation methodology in its Application or direct testimony and parties have therefore had no opportunity to evaluate that proposal.

The Commission should instead consider changes to PG&E's common cost allocation methodology—including the allocation of both ESA and Collateral Costs—in a Phase II. While PG&E's ESA Cost allocation methodology is currently Scoping Item 9(a), the IOUs' opening comments revealed sharply contrasting approaches to ESA Cost accounting and recovery: PG&E allocates "fixed" ESA Costs to its ERRA, PABA and NSGBA;[11] SCE forecasts no "fixed" ESA Costs;[12] and San Diego Gas & Electric Company (SDG&E) recovers its ESA Costs through distribution rates.[13] In light of the significant and unexplained disparities between the IOUs with respect to the same category of "Fixed Generation Costs," the Commission should move the ESA Cost allocation issue into a consolidated Phase II in order to address that issue consistently and comprehensively across all three IOU service territories.

The Commission should also reject PG&E's proposal to address its "Replacement Resource Adequacy (RA) Costs" in Phase II of this proceeding. PG&E's current approach—which is to assign the costs of substitute capacity during outages to the balancing account from which the need for substitute capacity originated—is a settled issue recently litigated in the utility's 2019 ERRA Compliance proceeding. The Commission should not revisit or allow PG&E to relitigate this settled issue in this proceeding.

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10 PG&E Opening Comments at 6-7.

11 *Id*. at 5.

12 SCE Opening Comments at 3.

13 SDG&E Opening Comments at 3.

I. The IOUs' opening comments reveal inconsistencies in the way the IOUs define "Fixed Generation Costs"

The IOUs do not define "Fixed Generation Costs" consistently, which makes it difficult to compare the IOUs' costs (and any projected impacts on a hypothetical last remaining bundled customer) on an "apples-to-apples" basis. PG&E's definition of "Fixed Generation Costs" mirrors the ALJ Ruling: "costs that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation." PG&E's response to Question 2 (Table Identifying Cost Categories), however, suggests that many of its "Fixed Generation Costs" are in fact volumetric costs that will decrease based on its customers' usage pattern.[14] SCE echoes the definition of "Fixed Generation Costs" in the ALJ Ruling, but clarifies that its definition excludes energy costs.[15] SDG&E, in sharp contrast with PG&E and SCE, defines "Fixed Generation Costs" as "costs that do not diminish as load departs."[16] SDG&E's definition leads it to list, in its response to Question 2, costs that change based on the amount of operating time associated with electricity generation (*i.e.*, costs that are conventionally considered "variable", not "fixed", such as generation fuel costs).[17]

The IOUs contrasting definitions of "Fixed Generation Cost" are clear evidence that there is no consensus around what categories of generation costs are "fixed", and they demonstrate the issue would benefit from further discussion beyond the accelerated comment schedule the ALJ Ruling affords. In order to better delineate the issues raised in the ALJ Ruling, the Commission

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14 PG&E Opening Comments at 1.

15 SCE Opening Comments at 1.

16 SDG&E Opening Comments at 1.

17 *Id*. at 1-4.

should therefore give parties a less constrained opportunity to discuss the appropriate definition of "Fixed Generation Costs" and probe other parties' definitions.

That discussion, however, should not occur in the current phase of each IOU's ERRA Forecast proceeding. The limited purpose of the ERRA Forecast proceedings is to fulfill the IOUs' obligation under Pub. Util. Code Section 454.5(d)(3) to forecast generation rates for the following year based on forecasted load and forecasted balances in the ERRA and other balancing accounts established by prior Commission decisions.[18] The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[19] The Commission should therefore adopt CalCCA's recommendation and open a consolidated Phase II of the IOU's ERRA Forecast proceeding to address the issues triggered by the ALJ Ruling. Among those issues, the parties should consider the threshold question: "What is a reasonable definition of Fixed Generation Costs for all three IOUs?"[20]

II. The IOUs' Opening Comments confirm the issues triggered by the ALJ Ruling do not require urgent Commission action

While the ALJ Ruling raises several weighty issues, the Commission need not rush to resolve any of those issues, for at least two reasons. First, as CalCCA explained in opening comments, none of the three service territories is near the extreme "last bundled customer" scenario the ALJ Ruling lays out. SCE, for example, correctly describes the "last bundled customer" scenario as "extreme and highly improbable", because "[w]hile SCE's bundled service

18 *See* CalCCA Opening Comments at 8; SCE Opening Comments at 6 (stating the objective of SCE's 2024 ERRA Forecast application is "the timely approval of the forecasted revenue requirement and cost recovery associated with fuel and purchased power for 2024.")

19 CalCCA Opening Comments at 9.

20 CalCCA presents other potential Phase II scoping issues triggered by the ALJ Ruling at page 3 of its Opening Comments.

customer load has decreased in recent years, SCE has no indication that the trend will continue such that only a single bundled service customer would remain."[21]

Second, as CalCCA explained in Opening Comments, and as the IOUs' opening comments illustrate, several of the IOUs' fixed generation cost categories are already spread across bundled and unbundled customers through balancing accounts other than ERRA.[22] SDG&E's "Fixed Generation Cost" table, for example, excludes many of the "Fixed Generation Costs" it identified in its response to Question 1,[23] explaining that those costs "are constant for the last remaining bundled customer, before and after load departure, because all customers pay for those costs."[24] Indeed, as bundled customer departures have increased, departed customers have taken on more of the IOUs' "Fixed Generation Costs." As SCE correctly explains, "the establishment of cost recovery mechanisms [that] allocate costs across both bundled service and departing load customers, such as the PABA with its vintaged cost recovery, greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend)."[25] That means even in the extreme and unlikely "last remaining bundled customer scenario," that customer would only pay for those costs in the IOU's ERRA balancing account, which would include a fraction of the IOU's total Fixed Generation Costs.

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21 SCE Opening Comments at 5.

22 *See* CalCCA Opening Comments at 5; PG&E Opening Comments at 5 (noting that certain of its Fixed Generation Costs are recovered through balancing accounts other than ERRA, and "such broader cost allocation does not shift costs to remaining bundled service customers.")

23 Those include costs in the Portfolio Allocation Balancing Account (PABA), Transition Cost Balancing Account. (TCBA), Local Generating Balancing Account (LGBA), Modified Cost Allocation Mechanism Balancing Account (MCAMBA), the Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA). SDG&E Opening Comments at 2.

24 SDG&E Opening Comments at 4.

25 SCE Opening Comments at 5.

In light of the IOUs' current bundled customer counts, and the existing cost recovery mechanisms in place to ensure several Fixed Generation Costs are spread to all IOU customers, the Commission can and should act deliberately in addressing the issues triggered by the ALJ Ruling. A consolidated Phase II would give the Commission the breathing room necessary to do so.

A. The Commission should reject PG&E's attempt to inject a new issue into its ERRA Forecast Proceeding at the eleventh hour

Among its "Fixed Generation Costs," PG&E identifies the costs it pays to financial institutions for posting collateral to counterparties for its electric generation portfolio ("Collateral Costs").[26] PG&E allocates Collateral Costs to ERRA and PABA using common cost allocation factors based on the prior year's adopted net revenue requirements (similar to its treatment of ESA costs), and proposes to modify that methodology and allocate Collateral Costs based on gross generation authorized costs in the current phase of this proceeding.[27]

PG&E's proposal is a wholly improper attempt to inject a new issue into this proceeding at the eleventh hour. While PG&E's Application and direct testimony proposed similar modifications to the manner in which PG&E allocates **ESA costs**, PG&E did not propose to apply that modified methodology to its Collateral Costs nor did it provide any justification for doing so.[28] PG&E proposes to change the way it allocates its Collateral Costs for the first time in its opening comments on the ALJ Ruling.

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26 PG&E Opening Comments at 3.

27 *Id*. at 6.

28 *See* PG&E Direct Testimony at 5-6 – 5-7 (discussing PG&E's 2024 Collateral Costs, but making no proposal to change the underlying allocation methodology); 9-10 – 9-11 (discussing a change to the methodology for allocating ESA costs to the generation-related balancing accounts, but making no proposal related to Collateral Costs).

Intervenor testimony in this proceeding is due three weeks from the date PG&E filed its opening comments.[29] Parties simply do not have sufficient time to evaluate PG&E's new proposal and determine whether allocating Collateral Costs based on gross generation authorized costs would be consistent with applicable rules, regulations, resolutions and prior Commission decisions. The Commission should not, therefore, consider or make any changes to PG&E's allocation of Collateral Costs in the current phase of this ERRA Forecast proceeding.

Any modifications to PG&E's methodology for allocating Collateral Costs may, however, be an appropriate topic for Phase II of this proceeding. Moreover, to the extent the Commission creates a Phase II of this proceeding, the Commission should address the allocation of both ESA Costs and Collateral Costs in that phase. While PG&E's allocation of ESA Costs is currently within scope for this phase of this proceeding (Scoping Issue 9(a)), moving the issue to a Phase II will not only ensure the Commission avoids contravening the prohibition on policymaking in expedited ERRA Forecast cases, but will also ensure the Commission addresses the allocation and recovery of ESA and Collateral costs consistently and comprehensively (across common cost categories, but also across the three IOU service territories, assuming the Commission consolidates each IOU's Phase II). As discussed above, the IOUs' opening comments on the ALJ Ruling reveal significant differences between the IOUs' ESA costs, including the magnitude of those costs, how those costs are recorded, and how those costs are recovered from customers. These disparities indicate the Commission would benefit from more comprehensive record development regarding the IOUs' treatment of ESA and Collateral Fixed Generation Cost categories, once the significant work related to PG&E's Forecast Application and October Update is complete.

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[29] A.23-05-012, Assigned Commissioner's Scoping Memo and Ruling at 6 (Aug. 3, 2023).

B. The Commission Should Not Address Replacement Resource Adequacy Costs in a Phase II of this Proceeding

In its opening comments, PG&E explains it counts its costs associated with resource outages and outage replacement (Replacement Resource Adequacy (RA) Costs) as "Retained RA" and assigns those costs to its bundled customers.[30] PG&E recommends consideration of Replacement RA Costs in a Phase II of this proceeding, and presumably seeks to change the way it records and recovers those costs.[31]

While CalCCA supports consideration of several issues raised by the ALJ Ruling in a Phase II of this proceeding,[32] the Commission should not address PG&E's Replacement RA Costs in Phase II. PG&E correctly assigns the costs of substitute capacity during outages to the balancing account from which the need for substitute capacity originated. In other words, if an ERRA resource is on outage, PG&E appropriately records the costs of substitute resources to ERRA and recovers those costs from bundled customers. Any other approach—*i.e.*, requiring unbundled customers to pay for the costs of replacing resources needed for bundled customer compliance—would unfairly require those customers to subsidize bundled customers.

PG&E, the Cal Advocates, and several CCAs ("Joint CCAs") recently addressed this issue in PG&E's 2019 ERRA Compliance proceeding, A.20-02-009. In that proceeding, the Joint CCAs observed PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages. Despite using those PCIA-resources to serve bundled customers only, PG&E incorrectly counted the substitution capacity as "Unsold RA" in the PABA, rather than counting that capacity as "Retained RA" and charging bundled customers

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30 PG&E Opening Comments at 4.

31 *Id*. at 7.

32 *See* CalCCA Opening Comments at 8-11.

for the use of that capacity.[33] PG&E ultimately agreed those costs should have been charged to bundled customers, and accordingly adjusted $4.5 million in PABA from Unsold RA to Retained RA. The Commission ultimately approved the parties' settlement in that proceeding, which reflected PG&E's agreement with respect to the appropriate treatment of substitution capacity costs.[34] PG&E now conducts a regular accounting review of ERRA, PABA and CAM to make sure those portfolios do not "lean on" each other. Where PG&E uses resources from one portfolio to substitute capacity for resources in another portfolio, it transfers the related costs to the balancing account associated with the second portfolio. PG&E has followed this approach in each of its ERRA Compliance cases since addressing the issue in A.20-02-009. The Commission should not revisit or allow PG&E to relitigate this settled issue in a Phase II of this proceeding.

III. Conclusion

CalCCA appreciates the opportunity to submit these reply comments. For the reasons in its opening and reply comments on the ALJ Ruling, CalCCA requests the Commission adopt its recommendations. To the extent the Commission initiates a consolidated Phase II of the IOUs' 2024 ERRA Forecast proceedings, CalCCA looks forward to continuing to work with the parties to this proceeding, as well as the other IOUs, on issues related to the IOUs' Fixed Generation Costs in that consolidated Phase II.

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33 A.20-02-009, *Prepared Direct Testimony of Brian Dickman on behalf of Joint Community Choice Aggregators* at 28 (Jul. 10, 2020).

34 *See* A.20-02-009, D.21-07-013 at 12 (approving settlement agreement, and describing parties' compromises, including PG&E's agreement to make an adjustment of $4.5 million in the PABA from Unsold RA to Retained RA because PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages.)

Respectfully submitted,

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Counsel to CalCCA

ATTACHMENT A

SCE OPENING COMMENTS

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement	A.23-06-001

OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

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Dated: **August 16, 2023**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement	A.23-06-001

OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

Pursuant to the *Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs* (Ruling) dated August 1, 2023, Southern California Edison Company (SCE) respectfully submits its Opening Comments.

I. INTRODUCTION

The Ruling directs the parties to submit comments on the issues regarding investor-owned utility (IOU) generation costs recovered through the Energy Resource Recovery Account (ERRA) Balancing Account (BA) that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation (referred to as "Fixed Generation Costs").[1] As discussed below, a relatively limited amount of SCE's Fixed Generation Costs are recovered through the ERRA BA. The majority of SCE's Fixed Generation Costs are recovered through SCE's Portfolio Allocation Balancing Account (PABA), New System Generation Balancing Account (NSGBA) and

[1] *See* Ruling, p. 1. SCE interprets the phrase "costs that do not change based on . . . the amount of operating time associated with the electricity generation" in the Ruling's definition to exclude the circumstance where the generation facility is not operational (e.g., an unplanned outage) because if it was not operating at all, SCE would likely not incur any costs. Rather, SCE interprets this phrase to include capacity costs but not energy costs because energy costs are based on the amount of electricity generation while capacity costs are typically based on the unit's availability.

other balancing accounts that allocate cost recovery to both bundled service and departing load customers.

II. SCE'S RESPONSES

A. Identify and briefly describe each category of Fixed Generation Costs in this proceeding.

SCE's annual ERRA Forecast application includes a forecast of fuel and purchased power (F&PP) costs for the primary purpose of setting generation rates for SCE's bundled service customers. SCE's F&PP costs are recovered across a variety of cost recovery mechanisms, including SCE's ERRA BA, PABA, NSGBA, Modified Cost Allocation Mechanism Balancing Account (MCAMBA), Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA), BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA), and the Base Revenue Requirement Balancing Account (BRRBA-D). SCE's response in Question B below lists the Fixed Generation Costs included in the instant application for the Commission's review and approval.

The Fixed Generation Costs in SCE ERRA BA are associated primarily with gas transportation and capacity costs that are recovered solely from SCE's bundled service customers and constitute a relatively limited amount of SCE's total Fixed Generation Costs. The majority of SCE's Fixed Generation Costs are recovered through SCE's PABA and NSGBA. This includes costs associated with Competitive Transmission Charge (CTC) contract costs, Western Renewal Energy Generation Information System, Power Charge Indifference Adjustment (PCIA)-eligible Cogeneration/Renewables, system reliability procurement, resource adequacy and local capacity requirements (LCR), cost allocation mechanism (CAM) baseload cogeneration, renewables energy management, the adjustments from the Green Tariff Shared Renewables (GTSR), Hoover Interutility Contract, and other base revenue requirements. There are also limited Fixed Generation Costs associated with the MCAMBA, and BRRBA-D that result from system reliability and LCR capacity.

B. **<u>Please complete the following table by filling in every blank cell – if any cost categories were identified in question 1 that are not included in this table, please include them.</u>**

In the table below, SCE included only Fixed Generation Costs included in the 2024 ERRA Forecast application. This does not include the variable portion of the costs that are included in the application.

Cost	Balancing Account Used for Tracking	Estimated 2023 Cost	Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Service Customer **
Competitive Transmission Charge Contract Costs	PABA	$7,164,867	$12,703
California Independent System Operator and North American Electric Reliability Corporation Costs	ERRA BA, PABA	$0	$0
Hedging-related Costs	ERRA BA	$0	$0
Western Renewal Energy Generation Information System Costs	PABA	$2,669	$5
PCIA-related Cogeneration/Renewables Costs	PABA	$3,782,407	$6,706
Electric Supply Administration Costs	*N/A*	$0	$0
Replacement Resource Adequacy Costs	*N/A*	$0	$0
2018 Integrated Distributed Energy Resources (IDER) Request for Offers (RFO)	ERRA BA	$322,560	$322,560
Distribution Deferral (DDCCBA-DIDF)	ERRA BA	$161,000	$161,000

Gas Transportation Costs	ERRA BA	$3,034,564	$3,034,564
Modified Cost Allocation Mechanism (MCAM) Capacity Costs (previously System Reliability Procurement Memorandum Account)	PABA, NSGBA, MCAMBA	$89,206,190	$158,157
Resource Adequacy (RA) Capacity Costs	PABA	$483,554,554	$857,313
Local Capacity Requirements (LCR) Capacity Costs	PPPAM and BRRBA-D	$37,364,803	$66,244
Cost Allocation Mechanism (CAM) Related RA Costs	NSGBA	$519,743,616	$921,476
Hoover Inter-utility Contract Payments	PABA	$4,742,861	$8,409
CAM Baseload Cogeneration Costs	NSGBA	$22,679,489	$40,209
Renewables Energy Management Costs	PABA	($109,929,827)	($194,899)
Green Tariff Shared Renewables (GTSR) Program Adjustments	PABA	($9,705,089)	($17,207)
Legacy Utility-Owned Generation (UOG) Base Revenue Requirement (Litigated in GRC)	PABA	$503,935,787	$893,449
Mountainview, Fuel Cells, Solar Photovoltaic Program (SPVP) Base Revenue Requirement (Litigated in GRC)	PABA	$223,033,866	$395,426
Total		**$1,779,091,317**	**$3,520,272**

** The estimated cost that would remain if SCE had a single remaining bundled customer.

C. <u>Should any issues associated with Fixed Generation Costs be addressed in this proceeding? If your answer is yes, briefly identify those issues and state whether those issues should be addressed with the other issues in this proceeding or in a separate phase after the other issues are addressed in a Commission decision.</u>

SCE is unaware of any issues associated with its Fixed Generation Costs that need to be addressed in this proceeding or elsewhere. As shown above, SCE estimates approximately $3.52 million of Fixed Generation Costs in SCE's ERRA BA. By contrast, SCE estimates approximately $1.78 billion in Fixed Generation Costs in total for all Balancing Accounts associated with the instant ERRA Forecast application. As requested in the Ruling's table above, SCE has shown the cost responsibility for the hypothetical one remaining bundled service customer. In such a circumstance, that customer would be responsible for the entire amount of fixed costs in the ERRA BA. However, this is an extreme and highly improbable assumption. While SCE's bundled service customer load has decreased in recent years, SCE has no indication that the trend will continue such that only a single bundled service customer would remain.

Moreover, the establishment of cost recovery mechanisms allocate costs across both bundled service and departing load customers, such as the PABA with its vintaged cost recovery, greatly reduces the risk of stranded costs associated with a declining bundled service population (even assuming a continuing trend). This is because the departing load customers would continue to pay their cost responsibility through the PCIA and CTC for PABA, and other rates that broadly allocate procurement costs, such as CAM for NSGBA, including Fixed Generation Costs recovered through the operation of these SCE Balancing Accounts.

D. **<u>Should the three 2024 ERRA Forecast proceedings be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs? Please explain your answer and, if your answer is yes, state when the consolidation should occur.</u>**

No. SCE submit that it has no issue associated with Fixed Generation Costs and therefore no reason to support consolidation of it time-sensitive 2024 ERRA Forecast application with other IOUs' separate ERRA Forecast applications for the purpose of addressing Fixed Generation Costs. Should the Commission decide there is a need to address Fixed Generation Costs in a consolidated fashion, it should do so in a Rulemaking. In no event should consideration of Fixed Generation Costs delay the objective of SCE's 2024 ERRA Forecast application, which is the timely approval of the forecasted revenue requirement and cost recovery associated with the fuel and purchased power for 2024.

III. <u>CONCLUSION</u>

SCE appreciates the opportunity to submit these opening comments.

Respectfully submitted,

JANET S. COMBS

/s/ Janet S. Combs

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ATTACHMENT B

SDG&E OPENING COMMENTS

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

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) for Approval of its 2024 Electric Procurement Revenue Requirement Forecasts, 2024 Electric Sales Forecast, and GHG-Related Forecasts	A.23-05-013

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

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August 16, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION
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Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) for Approval of its 2024 Electric Procurement Revenue Requirement Forecasts, 2024 Electric Sales Forecast, and GHG-Related Forecasts	A.23-05-013

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO COMMENT REGARDING FIXED GENERATION COSTS

I. INTRODUCTION

Pursuant to the August 1, 2023, *Administrative Law Judge Ruling Directing Parties to Comment Regarding Fixed Generation Costs* (the "ALJ Ruling"), San Diego Gas & Electric Company ("SDG&E") hereby submits its Opening Comments addressing each of the four issues identified regarding generation costs recovered through the Energy Resource Recovery Account ("ERRA") Balancing Account that do not change based on the amount of electricity customers use ("Fixed Generation Costs.")[1]

II. DISCUSSION OF ISSUES IN ALJ RULING

1. Identify and briefly describe each category of Fixed Generation Costs in this proceeding.

SDG&E's primary electric commodity cost recovery balancing accounts and the category of Fixed Generation Costs tracked in each balancing account are as follows:

- ERRA – Paid by bundled customers. Fixed Generation Costs include:
    - o Up-to-market Competitive Transition Charge ("CTC") contract costs and CTC California Independent System Operator ("CAISO") net revenues,

[1] For purposes of these comments, SDG&E is interpreting "Fixed Generation Costs" to mean those costs that do not diminish as load departs.

and CAISO/North American Electric Reliability Corporation ("NERC") miscellaneous costs.

- Portfolio Allocation Balancing Account ("PABA") – Paid by both bundled and unbundled customers. Charges are developed based on load forecasts. Fixed Generation Costs include:
    - Generation fuel, contract above-market cost, utility-owned resource above-market cost, including greenhouse gas ("GHG") cost.
- Transition Cost Balancing Account ("TCBA") – Paid equally by both bundled and unbundled customers. Paid by all customers through utility distribution company ("UDC") rates. Fixed Generation Costs include:
    - Above-market CTC contract costs
- Local Generating Balancing Account ("LGBA") – Paid equally by both bundled and unbundled customers. Paid by all customers through UDC rates. Fixed Generation costs include:
    - Contract costs and associated GHG cost, utility-owned resource costs, and net CAISO revenues.
- Modified Cost Allocation Mechanism Balancing ("MCAMBA") – Paid by both bundled and unbundled customers (these costs primarily flow through PABA). Fixed Generation Costs include:
    - Contract cost, utility-owned resource cost, and net CAISO revenues.
- Tree Mortality Non-Bypassable Charge Balancing Account ("TMNBCBA") – Paid equally by both bundled and unbundled customers through the public purpose programs ("PPP") charge, which is part of UDC rates. Fixed Generation Costs include:
    - Contract costs and net CAISO revenues.

2. **Please complete the following table by filling in every blank cell – if any cost categories were identified in question 1 that are not included in this table, please include them.**

<table>
<tr><th>Cost</th><th>Balancing Account Used for Tracking</th><th>Estimated 2023 Cost</th><th>Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Customer[2]</th></tr>
<tr><td>Competitive Transmission Charge Contract Costs</td><td>ERRA/TCBA</td><td>ERRA: $24.0M, offset by ($22M) in CAISO revenues. (paid by bundled customers only)
TCBA: $10.6M (paid by all customers)</td><td>ERRA: $2.0M = net contract cost</td></tr>
<tr><td>California Independent System Operator and North American Electric Reliability Corporation Costs</td><td>ERRA</td><td>ERRA: $423.3M in load costs and $3.0M in miscellaneous CAISO and NERC costs, offset by ($17.9M) in supply revenues.</td><td>CAISO load cost for the last customer would be the current market price of electricity multiplied by the last customer's volume used.
Other CAISO and NERC costs remaining in ERRA are forecasted to be $3.0M.</td></tr>
<tr><td>Hedging-related Costs</td><td>ERRA</td><td>$10.2M</td><td>$0</td></tr>
<tr><td>Western Renewal Energy Generation Information System Costs</td><td>ERRA</td><td>$.018M</td><td>$0</td></tr>
<tr><td>ERRA-related Cogeneration/Renewables Costs</td><td colspan="3">Please see response to Competitive Transmission Charge Contract Costs for the ERRA portion of CTC costs.</td></tr>
<tr><td>Electric Supply Administration Costs</td><td colspan="3">Administration costs are determined in SDG&E's General Rate Case proceeding. The cost for the last bundled customer will remain the same after load departure, because it is part of the electric distribution volumetric rate.</td></tr>
<tr><td>Replacement Resource Adequacy Costs</td><td>ERRA</td><td>Not forecasted due to low predictability</td><td>This would be an immaterial amount.</td></tr>
</table>

2 The estimated cost that would remain if the investor-owned utility experienced load departure such that it had a single remaining bundled customer.

Cost	Balancing Account Used for Tracking	Estimated 2023 Cost	Estimated 2023 Cost for a Hypothetical Last Remaining Bundled Customer[2]
Other Costs: RPS and resource adequacy compliance costs	ERRA	$92.7M	Approximately $157 per year

[1] The estimated cost that would remain if the investor-owned utility experienced load departure such that it had a single remaining bundled customer.

In addition to filling out the table, SDG&E provides the following additional information/comments:

- 2023 forecasted CTC costs of $34.6M are recovered in ERRA for the up-to-market portion, and the above-market portion is recovered in TCBA. The costs in ERRA are offset by CAISO revenues for CTC contracts, which are forecasted to be $22.0M in 2023. The remaining costs of $2.0M would be considered up-to-market according to the CTC benchmark and therefore recovered in ERRA. The exact amount of actual CAISO revenues received will depend on market prices at the time, and this will affect the amount still to be recovered in ERRA.

- CAISO load cost is volumetric and calculated based on the TOU market price. Having only one customer would mean that customer is exposed to potential high rates due to under collections if electricity prices spike during the time they are using electricity.

- Hedging costs for one bundled customer would be close to zero, because hedging costs are load-based per the Bundled Procurement Plan and are therefore volumetric.

- Western Renewable Energy Generation Information System (“WREGIS”) costs for one bundled customer would be close to zero. Any additional WREGIS costs would be recovered in PABA, because they are a part of the cost of renewable contracts.

- Costs in the response to question 1. that are not included in the table above are those that are constant for the last remaining bundled customer, before and after load departure, because all customers pay for those costs.

3. Should any issues associated with Fixed Generation Costs be addressed in this proceeding? If your answer is yes, briefly identify those issues and state whether those issues should be addressed with the other issues in this proceeding or in a separate phase after the other issues are addressed in a Commission decision.

The issue of the CTC up-to-market costs that remain in ERRA should be addressed. Pursuant to D.02-12-027 in Rulemaking 02-01-011[3], a market benchmark proxy is utilized to determine the above-market costs that can be recovered in the TCBA from bundled and unbundled customers. However, that can result in significant costs being recovered through ERRA during periods when the CAISO revenues received were less than the imputed up-to-market costs. The practice of using a market benchmark proxy should be replaced with a practice of simply measuring actual revenues against actual costs and recording the difference in the TCBA. SDG&E recommends that this issue should be addressed in a separate phase of the ERRA Forecast proceeding after a Commission decision has been issued on the main issues presented in the May 15 ERRA Forecast Application and the upcoming October Update. Alternatively, the Commission could consider addressing the issue in R.02-01-011, though that proceeding has been closed since 2021.

4. Should the three 2024 ERRA Forecast proceedings be consolidated for the sole purpose of addressing any issues associated with Fixed Generation Costs? Please explain your answer and, if your answer is yes, state when the consolidation should occur.

SDG&E does not believe that it is necessary to consolidate the three 2024 ERRA Forecast Proceedings for purposes of addressing issues related to Fixed Generation Costs. The issue SDG&E identified in question 3 above appears to be specific to SDG&E and therefore it does not appear that any efficiencies would be gained by consolidation. The ERRA forecast

[3] Ordering Instituting Rulemaking regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.

proceeding should only be consolidated in instances were broad-ranging, state-wide issues need to be addressed. However, should the Commission or the other IOUs identify common issues related to the Fixed Generation Costs, then perhaps it might be appropriate to either consolidate the ERRA proceedings, reopen the PCIA rulemaking (R.17-06-026), or perhaps open a new rulemaking to address common issues.

III. CONCLUSION

SDG&E appreciates the opportunity to submit these Opening Comments to the ALJs' Ruling.

Respectfully submitted,

/s/ Roger A. Cerda

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Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

August 16, 2023

August 23, 2023

The Honorable Patty Murray
Chairwoman
Senate Appropriations Committee
Washington, DC 20510

Dear Chairwoman Murray,

On behalf of our collective millions of members and supporters across the environmental, environmental justice, and public health communities, we write to thank you for your strong leadership throughout the Senate Appropriations Committee's Fiscal Year 2024 bill markups. We appreciate your work to responsibly and expediently shepherd the Senate through the appropriations process. Most importantly, we commend you for defending critical climate funding and warding off potential poison pill riders. Our communities will continue to ardently oppose any attempts to hamstring regulations or repeal funding to protect the climate and our public health, especially funding from the Inflation Reduction Act (IRA).

While we commend your committee for adhering to the spending deal struck in the House majority-manufactured default crisis, the budget caps set spending at levels far below what the President requested in his Fiscal Year 2024 Budget and far from what is required to adequately address the climate crisis, as you know. Insufficient funding limits agencies' abilities to develop and staff robust, impactful programs or enforce regulations to protect families, the environment, and the economy. Bad actors and polluters act with impunity, injecting harmful chemicals into our air, water, and land, disproportionately affecting communities of color.

As the country bakes under record-breaking levels of heat fueled by climate change, and as drought, flood and fire ravage communities, we cannot afford any cuts to climate funding. The climate crisis and its impacts are becoming more severe, more dangerous, and more costly with each day. As you well know, rescissions to the IRA and lower spending levels to the agencies implementing these critical investments would be a disastrous outcome for public health, the climate, the economy, and our future. It is incumbent on our Congressional leaders to enable agencies to do their critical work to combat climate change and to ensure a livable planet for all.

We support your efforts to protect this funding and defend against attempts to undermine the IRA. While our groups all work on many aspects of appropriations related to environmental protection, climate, and public health, our joint defense priorities for the Fiscal Year 2024 spending bills include:

- We oppose measures that rescind or cap IRA funds.

- We oppose measures that weaken programs aimed at alleviating pollution in overburdened communities, addressing environmental injustice, or meeting the Administration's Justice40 goals.
- We oppose measures that cut agencies' core capacities, including staffing, and restrict their ability to efficiently and effectively distribute funds and execute environmental, public health, and other climate-related programs and regulations.
- We oppose measures to limit or block agencies' ability to implement or enforce bedrock environmental laws or regulations.
- We oppose measures that weaken or undermine the climate wins gained through the IRA, redefine the IRA's pro-climate congressional intent, or inhibit the Administration's ability to abide by the IRA's pro-climate congressional intent.

Thank you again for your leadership. We stand with you and urge you to remain steadfast in fighting for climate funding and opposing attempts to further reduce spending levels. We look forward to continuing to work with you and other climate champions in Congress to protect our public health and our planet.

Sincerely,

Climate Action Campaign
Alaska Wilderness League
Alliance for Clean Energy New York
Alliance of Nurses for Healthy Environments
American Hiking Society
American Trails
Appliance Standards Awareness Project
Arizona Climate Action Coalition.
Change the Chamber*Lobby for Climate
Clean Water Action
Climate Hawks Vote
Climate Mayors
Climate Nexus
Dayenu: A Jewish Call to Climate Action
Dream.Org
Earthjustice
East Bay Community Energy (EBCE)
Elders Climate Action-Arizona
Elevate
Endangered Species Coalition
Environment America

Environmental Defense Fund
Environmental Investigation Agency
Environmental Working Group
Evergreen Action
Faith in Place
First Focus on Children
Georgia Interfaith Power and Light (GIPL)
Green the Church
Greenlatinos
Health Care Without harm
Impact Fund
Institute for a Progressive Nevada
Interfaith Power & Light
League of Conservation Voters
Local Initiatives Support Corporation
Los Padres ForestWatch
Marin Clean Energy - MCE
Medical Society Consortium on Climate and Health
Michigan Clinicians for Climate Action
Michigan League of Conservation Voters
Michigan Sustainable Business Forum
Moms Clean Air Force
Moms Clean Air Force - Arizona
Moms Clean Air Force - Georgia
Moms Clean Air Force- Michigan
National Audubon Society
National Ocean Protection Coalition
National Wildlife Federation
New Progressive Alliance
Natural Resources Defense Council
PennEnvironment
PennFuture
Physicians for Social Responsibility
Poder Latinx
Public Justice Center
Rachel Carson Council
Rewiring America
Service Employees International Union (SEIU)
Sierra Club
Silvix Resources

Southern Environmental Law Center
Southern Utah Wilderness Alliance
The Wilderness Society
Union of Concerned Scientists
Urban Sustainability Directors Network (USDN)
Waterkeeper Alliance
WE ACT for Environmental Justice
West Michigan Environmental Action Council

CC:
Senate Majority Leader Chuck Schumer
House Minority Leader Hakeem Jeffries
House Appropriations Ranking Member Rosa DeLauro
White House Deputy Chief of Staff John Podesta
National Climate Advisor Ali Zaidi
Members of the Senate Democratic Caucus
Members of the House Democratic Caucus