JULY FILINGS

July 1, 2024

VIA ELECTRONIC MAIL

Public Utilities Commission of the State of California
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Advice Letter 15-E **Apple Valley Choice Energy**	**Advice Letter 48-E** **Ava Community Energy**	**Advice Letter 41-E** **Central Coast Community Energy**
Advice Letter 9-E **Clean Energy Alliance**	**Advice Letter 27-E** **Clean Power Alliance**	**Advice Letter 29-E** **CleanPowerSF**
Advice Letter 10-E **Desert Community Energy**	**Advice Letter 6-E** **Energy For Palmdale's Independent Choice**	**Advice Letter 28-E** **Lancaster Energy**
Advice Letter 78-E **Marin Clean Energy**	**Advice Letter 9-E** **Orange County Power Authority**	**Advice Letter 34-E** **Peninsula Clean Energy**
Advice Letter 23-E **Pico Rivera Innovative Municipal Energy**	**Advice Letter 19-E** **Pioneer Community Energy**	**Advice Letter 10-E** **Pomona Choice Energy**
Advice Letter 13-E **Rancho Mirage Energy Authority**	**Advice Letter 21-E** **Redwood Coast Energy Authority**	**Advice Letter 20-E** **San Diego Community Power**
Advice Letter 21-E **San Jacinto Power**	**Advice Letter 35-E** **San José Clean Energy**	**Advice Letter 6-E** **Santa Barbara Clean Energy**
Advice Letter 32-E **Silicon Valley Clean Energy**	**Advice Letter 23-E** **Sonoma Clean Power**	**Advice Letter 18-E** **Valley Clean Energy**

RE: Joint CCAs' Community Choice Aggregator Financial Monitoring and Reporting Guidelines Tier 2 Advice Letter Submitted to Aid in the Implementation of Ordering Paragraph 7 of Decision 24-04-009

California Community Choice Association (CalCCA) submits this Tier 2 Advice Letter (Advice Letter) on behalf of Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power,

San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy[1] (collectively, the Joint CCAs). This Advice Letter is submitted to aid Energy Division staff in the implementation of Ordering Paragraph (O¶) 7 of Decision (D.)24-04-009[2] (the Decision) as well as provide clarity to the Joint CCAs on required reporting triggers. The Joint CCAs request the California Public Utilities Commission's (Commission) approval of the CCA Financial Monitoring and Reporting Guidelines document attached to this Advice Letter as Appendix A.

I. TIER DESIGNATION

The Joint CCAs hereby submit this Advice Letter with a Tier 2 designation.

II. EFFECTIVE DATE

This Tier 2 Advice Letter will become effective July 31, 2024, the 30th calendar day after the date submitted.

III. BACKGROUND

The Commission opened the Provider of Last Resort (POLR) proceeding, Rulemaking (R.) 21-03-011, on March 18, 2021, to implement Senate Bill (SB) 520 (Hertzberg 2019). SB 520 directed the Commission to develop rules and regulations for a POLR should a community choice aggregator (CCA) or Energy Service Provider cease load service. SB 520 identified the investor-owned utilities (IOUs) as the initial POLRs and ordered the Commission to ensure cost recovery, continuity of service and reliability, and continuation of California's clean energy goals.

R.21-03-011 considered, among other things, financial monitoring and reporting requirements that would provide the Commission with advance notice of CCAs' financial positions that may indicate a potential customer return to the POLR. D.24-04-009 adopted financial monitoring and reporting requirements aimed at "promot[ing] greater situational awareness for any CCA that is at risk of defaulting on its procurement obligations, and which may lead to the involuntary return of customers to POLR service."[3]

D.24-04-009 adopted two tiers of financial monitoring and reporting requirements for CCAs. Under the first tier, all CCAs, regardless of their financial standing or years of operation, are required to provide the Energy Division with a copy of their most recent audited financial information. The audited financial statement shall be provided once a year, in January or July, whichever comes earlier relative to the availability of the audited financial statement. Under the

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[1] The Joint CCAs have provided CalCCA with authority to submit this Advice Letter on their behalf.

[2] D.24-04-009, *Decision Implementing Senate Bill 520 Regarding Standards for Provider of Last Resort*, R.21-03-011 (Apr. 18, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M529/K986/529986322.PDF.

[3] *Id.* at 73.

second tier, CCAs must report additional financial information if they meet certain conditions indicative of financial strain.

IV. PURPOSE

Following the adoption of D.24-04-009, CalCCA files this Advice Letter supplementing D.24-04-009 with additional guidance on (1) how and when to evaluate the conditions for two-tier financial reporting, and (2) reported financial information for tier-two reporting. CalCCA files this Tier 2 Advice Letter on behalf of the Joint CCAs to request approval of the CCA Financial Monitoring and Reporting Guidelines document attached to this Advice Letter as Appendix A. CalCCA also provides a description of the Appendix here:

- Section 1 of Appendix A documents the Tier 2 reporting conditions and an explanation of each condition. Unless specified, Tier 2 reporting applies to CCAs that meet any one of the conditions.

- Section 2 of Appendix A documents how and when CCAs must report the occurrence of a Tier 2 condition. Depending on the condition, CCAs must report within 10 business days of the occurrence or within 10 days of the CCA's acceptance of its financial statement. It also documents its engagement with Energy Division and information that it must report to Energy Division upon meeting a Tier 2 condition.

- Section 3 discusses when a CCA may cease a previously triggered Tier 2 report.

- Section 4 documents how a CCA requests confidential treatment of market sensitive information reported to Energy Division.

- Section 5 of Appendix A describes the enforcement mechanism used to ensure that CCAs report to the Energy Division on time in accordance with the deadlines outlined in Section 2.

V. PROTEST

Anyone wishing to protest this Advice Letter may do so only by electronical mail. Protests must be received no later than 20 days after the date of this Advice Letter. Protests should be submitted to the Commission Energy Division at:

E-mail: EDTariffUnit@cpuc.ca.gov.

In addition, protests and all other correspondence regarding this Advice Letter should also be sent by electronical mail to the attention of:

California Community Choice Association
Attn: Evelyn Kahl
General Counsel and Director of Policy
regulatory@cal-cca.org

California Community Choice Association
Attn: Eric Little
Director of Regulatory Affairs
eric@cal-cca.org

California Community Choice Association
Attn: Lauren Carr
Senior Market Policy Analyst
lauren@cal-cca.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

VI. NOTICE

In accordance with G.O. 96-B, Section IV, a copy of this Advice Letter is being sent by electronic mail to each party of record in the official service list for R.21-03-011. For changes to this service list, please contact the Commission's Process Office at (415) 703-2021, or by electronic mail at Process_Office@cpuc.ca.gov.

VII. CORRESPONDENCE

All questions concerning this Advice Letter should be directed to Evelyn Kahl at (510) 980-9459, or by electronic mail at: regulatory@cal-cca.org.

VIII. CONCLUSION

The Joint CCAs respectfully request that the Commission approve the CCA Financial Monitoring and Reporting Guidelines document attached to this Advice Letter as Appendix A.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl
General Counsel and Director of Policy

cc via email:
Energy Division Tariff Unit (edtariffunit@cpuc.ca.gov)
Service List: R.21-03-011

APPENDIX A
TO
JOINT CCAS' COMMUNITY CHOICE AGGREGATOR FINANCIAL MONITORING AND REPORTING GUIDELINES TIER 2 ADVICE LETTER SUBMITTED TO AID IN THE IMPLEMENTATION OF ORDERING PARAGRAPH 7 OF DECISION 24-04-009

CCA FINANCIAL MONITORING AND REPORTING GUIDELINES

COMMUNITY CHOICE AGGREGATORS (CCA)
FINANCIAL MONITORING AND REPORTING GUIDELINES
UPDATED JULY 1, 2024

Decision (D.) 24-04-009 adopted two tiers of financial monitoring and reporting requirements for CCAs. Under the first tier, all CCAs, regardless of their financial standing or years of operation, are required to provide the Energy Division with a copy of their most recent audited financial information. The audited financial statement shall be provided once a year, in January or July, whichever comes earlier relative to the availability of the audited financial statement. Under the second tier, CCAs must report additional financial information if they meet certain conditions indicative of financial strain. This guideline document supplements D.24-04-009 with additional guidance on (1) how and when to evaluate the conditions for tier-two financial reporting, and (2) reported financial information for tier-two reporting.

1. Conditions that Trigger Tier-Two Financial Reporting

Tier 2 reporting applies to CCAs that meet any of the following conditions in Table 1:

Table 1: Tier-Two Reporting Conditions

Condition	Explanation
The CCA receives a credit rating below BBB-/Baa3 from S&P & Moody's	This condition applies only to CCAs who are downgraded from an investment grade rating to a noninvestment grade rating. This condition does not require all CCAs to obtain a credit rating.
Days Liquidity on Hand (DLOH) is less than 45 days *Note: this condition triggers Tier 2 reporting only if the Adjusted DSCR trigger is also met.*	DLOH is defined as a CCA's available unrestricted cash and investments and eligible unused bank letters of credit, credit agreements, and capacity under commercial paper programs, multiplied by 365. This amount shall then be divided by the total of the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
Adjusted Debt Service Coverage Ratio (DSCR) is less than 1.0 *Note: this condition triggers Tier 2 reporting only if the DLOH trigger is also met.*	Adjusted DSCR is defined as: Numerator: For the last twelve months, recurring revenue plus interest income plus withdrawals from a Rate Stabilization Fund, minus recurring cash operating expenses and General Fund Transfers over the prior twelve-month period (where recurring revenue and recurring expenses exclude special, one-time items, and annual operating expenses exclude depreciation and amortization expenses).

	Denominator: Aggregate debt service over the prior twelve-month period (i.e., principal, interest, and fees, as applicable, associated with the debt).
Cash reserves for the CCA fall below 5 percent of annual expenses	Cash reserves are defined as cash, cash equivalents, short-term investments, and unused credit facilities. The measure of cash reserves must be directly tied to the CCA. It should not consider a city's general fund cash reserves. Where "annual expenses" are defined as the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment	This condition is specific to the occurrence of an event of default for buyer non-payment after opportunities for disputes and cures have been exhausted as provided within the contract.
The CCA defaults to its CAISO scheduling coordinator due to non-payment	N/A
The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur	N/A

2. Tier-Two Reporting Requirements

The following conditions must be reported via a confidential letter to the Director of Energy Division within 10 business days of the occurrence:

- The CCA receives a credit rating below BBB-/Baa3 from S&P & Moody's;
- The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment;
- The CCA defaults to its CAISO scheduling coordinator due to non-payment; and
- The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur.

The following conditions must be reported via a confidential letter to the Director of Energy Division within 10 business days of the CCA's acceptance of a financial statement:[1]

- DLOH is less than 45 days and DSCR is less than 1.0; and

[1] CCAs regularly review and update financial statements. Unaudited financial statements should be prepared as soon as practicable and, in any event, within sixty days after the end of each month in which the trigger occurred. If updated financial information is obtained after such submittal, the CCA will provide that update to the Director of the Energy Division to help inform any prior trigger reporting.

- Cash reserves for the CCA fall below 5 percent of annual expenses.

Upon meeting any of the Tier 2 reporting conditions above and submitting the confidential letter to Energy Division, the CCA must meet with Energy Division as requested, up to one meeting per month, and provide the following information:

- Energy and hedging contracts for the next six months with term details;
- Status of all procurement contracts, in particular, those at risk of default;
- Detailed financial information as requested by the Commission including, but not limited to, the CCA's most recent financial statements and DLOH;
- Plan for financial correction and/or market exit.

3. Graduating from Tier-Two Reporting Requirements

A CCA will graduate from the Tier 2 reporting requirements if it does not meet any Tier 2 triggers (except for the insolvency/bankruptcy condition) for six consecutive months.

4. Confidentiality

If a CCA believes that its letter notifying the Energy Division of a triggered Tier 2 condition, or any of its attendant reporting, is market sensitive, the CCA should follow the regular Commission process for securing confidential treatment.

5. Enforcement

A CCA that fails to submit a letter to the Energy Division by the deadlines outlined in Section 2 will incur a penalty of $1,000 per incident plus $500 per day for the first ten days the filing was late and $1,000 for each day thereafter. Commission Staff and the Commission may take any action provided by law to recover unpaid penalties and ensure compliance with applicable statutes and Commission orders, decisions, rules, directions, demands, or requirements.

ADVICE LETTER SUMMARY FORM

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: California Community Choice Association

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Evelyn Kahl
Phone #: (510) 980-9459
E-mail: regulatory@cal-cca.org
E-mail Disposition Notice to: regulatory@cal-cca.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)
July 1, 2024

Advice Letter (AL) #: See Attached

Tier Designation: 2

Subject of AL: Joint CCA's Community Choice Aggregator Financial Monitoring and Reporting Guidelines Tier 2 Advice Letter Submitted to Aid in the Implementation of Ordering Paragraph 7 of Decision 24-04-009

Keywords (choose from CPUC listing):

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 7/31/24

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Evelyn Kahl
Title: General Counsel and Director of Policy
Utility/Entity Name: California Community Choice Association

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: regulatory@cal-cca.org

Contact Name: Lauren Carr
Title: Senior Market Policy Analyst
Utility/Entity Name: California Community Choice Association

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: lauren@cal-cca.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 79-E-A

Tier Designation: 2

Subject of AL: Supplemental: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing): COMPLIANCE

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-05-065, E-4999, E-5125,

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: 79-E

Summarize differences between the AL and the prior withdrawn or rejected AL: This AL makes corrections to the

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 8/16/24

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Amulya Yerrapotu
Title: Policy Analyst
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: (925) 378-6729
Facsimile (xxx) xxx-xxxx:
Email: ayerrapotu@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

July 8, 2024

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Supplemental Advice Letter 79-E-A

RE: Supplemental: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

PURPOSE

MCE hereby submits this supplement to Advice Letter 79-E addressing corrections to the 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program that was submitted on July 5, 2024.

This supplemental advice letter is made in accordance with General Order (GO) 96-B and General Rule 7.5.1, which authorizes utilities to make revisions or corrections to advice letters through the submittal of a supplement. This supplement replaces Advice Letter 79-E in part, and Attachment A of Advice Letter 79-E in its entirety.

BACKGROUND

Pursuant to Ordering Paragraphs ("OP") 2 and 4 of Resolution E-4999,[1] OP 3 of Resolution E-5125,[2] and OPs 2 and 3 of D.24-05-065,[3] Marin Clean Energy ("MCE") submitted MCE AL-79, the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT) program for the program year ("PY") 2025, on July 5, 2024.

On page 4 of Attachment A, in Table 1: MCE Budget Forecast for PY 2025, MCE inadvertently

[1] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. MCE's implementation Advice Letter, MCE AL 42-E/E-A/E-B was approved in Resolution E-5124, which brought MCE under the same program rules and reporting structure applicable to the IOUs.
[2] OP 3 of Resolution E-5125 directed that DAC-GT and CS-GT Annual Budget Advice Letters are to be submitted as Tier 2 ALs to allow for additional review and oversight.
[3] OP 2 of D.24-05-065 discontinues the CS-GT program and directs program administrators to transfer remaining capacity, customers, and programs into the DAC-GT program. OP 3 of D.24-05-065 makes several modifications to the DAC-GT program, which are reflected in this budget submission.

used an incorrect value for the Generation Cost Delta, incorrectly inflating energy consumption from program participants by 25%. This, in turn, impacts subsequent sums (Total DAC-GT PY 2025 Budget Forecast, Total DAC-GT Budget Request for PY 2025, and Total MCE Budget Request for PY 2025).

After correcting the error, the 2025 Generation Cost Delta, Total DAC-GT PY 2025 Budget Forecast, Total DAC-GT Budget Request for PY 2025, and Total MCE Budget Request are all reduced by $489,242.61. MCE now requests a total budget of $6,302,724 for PY 2025.

MCE is submitting a revised Attachment A to correct the error. Please discard the previously submitted Attachment A in its entirety.

PROPOSED MODIFICATIONS TO ADVICE LETTER 79-E

MCE proposes the following modification to Advice Letter 79-E, as shown in bold font.

"MCE hereby submits the budget request for PY 2025 for the DAC-GT program. Per Resolution E-4999, the budget request includes both the budget reconciliation for the previous PY (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). Because D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a project for the CS-GT program, MCE does not include CS-GT in the PY 2025 budget forecast. However, MCE continues to include CS-GT program costs in the PY 2023 budget reconciliation. In summary, MCE requests a total budget of **$6,302,724** for the DAC-GT program for PY 2025, including PY 2023 CS-GT reconciliation costs. Additional details can be found in Appendix A."

TIER DESIGNATION

This supplemental AL is submitted with a Tier 2 designation, the same Tier designation pursuant to OP 3 of Resolution E-5125.

EFFECTIVE DATE

MCE requests that this supplemental AL become effective concurrent with the original AL 79-E, 30 calendar days from the July 5, 2024 date filing.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002 and Application A.22-05-022.

For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

MCE requests that the Commission, pursuant to General Order 96-B, General Rule 7.5.1, maintain the original protest and comment period designated in advice letter 79-E. Protests must be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter shall be sent electronically to the attention of:

Amulya Yerrapotu
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: ayerrapotu@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Amulya Yerrapotu at (925) 378-6729 or by electronic mail at ayerrapotu@mcecleanenergy.org.

/s/ Amulya Yerrapotu

Amulya Yerrapotu
Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (925) 378-6729
Email: ayerrapotu@mcecleanenergy.org

Appendices

Appendix A: PY 2025 Budget Request
Appendix B: PY 2025 ME&O Plan

cc: Service List for R.14-07-002 and A.22-05-022

Budget Forecast for the Disadvantaged Communities Green Tariff Program for Program Year 2025

Proposed by Marin Clean Energy

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1. BACKGROUND

MCE is a program administrator (PA) of the Disadvantaged Communities (DAC) Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs. Per Resolution E-4999, annual program budgets must be presented by program and include the following budget line items:[1]

1. Generation cost delta, if any;[2]
2. 20 percent bill discount for participating customers;
3. Program administration costs: [3]
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance;
    e. Procurement;
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only).

In this program budget, MCE includes both the budget reconciliation for the previous program year (PY) (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). As D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a CS-GT project, MCE does not include CS-GT program costs for PY 2025, and only includes CS-GT costs in the budget reconciliation for PY 2023, but does not include CS-GT program costs for PY 2025.

In addition to budget reconciliation and forecast, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on:

1. Existing solar generation capacity at previous PY's close (i.e., December 31, 2023);
2. Forecasted solar generation capacity under contract for procurement in the upcoming PY;
3. Customers served at previous PY's close (i.e., December 31, 2023); and

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[1] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to MCE Advice Letter 42-E filed on May 7, 2020.

[2] Resolution E-4999 establishes that *above market* generation 9costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate."

[3] Resolution E-5124 established that PG&E can charge "CCA Integration Costs" to the programs; i.e. costs that incur to PG&E to enable CCAs to administer the programs (e.g., billing support functions). To date, CCAs have been including CCA integration costs on their budget ALs. On March 2, 2023, PG&E submitted Advice Letter 6872-E requesting that the CPUC approve a tariff modification to allow PG&E to record these CCA integration costs directly to PG&E's subaccount, instead of the CCAs seeking cost recovery. Therefore, MCE does not include the CCA integration cost in its 2025 budget forecast. However, MCE still includes the CCA integration cost in the calculation of its administration cost cap, per Resolution E-5124.

4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission's (CPUC or Commission) Energy Division staff directly:

1. Calculation of the generation cost delta;
2. Calculation of the 20% bill discount to participating customers.

2. BUDGET FORECAST FOR PY 2025

For PY 2025, MCE forecasts a total budget of $5,456,986 for the DAC-GT program. This budget forecast accounts for the program modifications established in D.24-05-065, including discontinuing the CS-GT program and rolling unused capacity into the DAC-GT program, increasing DAC-GT program capacity, and removing the Green-e certification requirement. A detailed budget forecast for each program by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PY 2025

Category	DAC-GT
Generation Cost Delta	$ 1,956,970
20% Bill Discount	$ 3,310,666
Program Administration	
Program Management	$ 22,820
Information Technology	$ 11,617
Billing Operations	$ 98,868
Regulatory Compliance	$ 18,996
Procurement	$ 15,690
Subtotal Program Administration	**$ 167,991**
Marketing, Education & Outreach	
Labor Costs	$ 6,357
Outreach and Material Costs	$ 15,000
Subtotal ME&O	**$ 21,357**
Total	**$ 5,456,985**

MCE provides a brief description of each of the budget line items below.

Generation Cost Delta
To date, MCE has been using interim solar generation resources to support the DAC-GT program while it is procuring a dedicated solar facility for the program. On June 20, 2022, the Commission

granted MCE's request to approve its dedicated DAC-GT power purchase agreement (PPA).[4] On November 11, 2024, the Commission approved MCE's first request to amend its dedicated DAC-GT PPA. On June 19, 2024, the Commission approved MCE's second request to amend its dedicated DAC-GT PPA. The new dedicated solar generation facility is expected to come online in early 2026. As such, the DAC-GT generation cost delta budget forecast for 2025 is based on the PPA price of the current interim solar generation resource, compared to the costs of serving customers under MCE's residential base tariff, the "Light Green" tariff.

Decision 24-05-065 approves a 50% expansion of MCE's DAC-GT program capacity. Decision 24-05-065 also rolls any unused CS-GT capacity into MCE's DAC-GT program. MCE's DAC-GT program now has a total capacity of 8.249 MW. MCE plans to enroll customers using an interim resource as it works to procure a resource to serve the remaining program capacity. MCE anticipates using the existing DAC-GT interim resource for this purpose.

20 Percent Bill Discount

As set forth in Resolution E-5124, MCE calculates the 20% bill discount on both the generation and transmission and distribution (T&D) portion of the electric bill for participating customers. The bill discount is then fully included on the generation portion of customer bills, i.e., the discount reduces the electric generation costs of a customer's bill only.[5] MCE then recovers these program costs via this budget AL filing.

In PY 2025, MCE expects to have approximately 5,805 customers enrolled in the DAC-GT program. D.24-05-065 expands MCE's DAC-GT program capacity by 3.609 MW. MCE estimates that it will be able to serve 2,540 customers with this new capacity, in addition to the existing 3,265 customers currently served by existing program capacity. MCE plans to enroll customers using an interim resource as it works to procure a new resource to serve the remaining program capacity. The PY 2025 forecast for the 20 percent bill discount is based on the actual average monthly bill discount provided to participating customers in 2023, with a 25% increase to account for forecasted increases in electricity rates. Future customers enrolled under the expanded capacity are assumed to have the same usage as existing customers.

Program Administration Costs

Program administration includes program development, management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations cover costs for ongoing billing operations and customer support, including the costs of MCE's third-party billing provider. While D.24-05-065 directs PG&E to provide a cost estimate for implementing an automated billing solution, it is uncertain whether such a solution will be implemented. As such, for the time being, MCE assumes that billing costs will remain as they are now. Regulatory Compliance covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, ongoing contract management, as well as annual renewable energy credit (REC) retirement and compliance functions. D.24-05-065 removes the Green-e certification requirement, instead ordering program

[4] See Disposition of MCE AL 63-E, MCE Disadvantaged Communities Green Tariff Program 2022 Power Purchase Agreement Approval.

[5] Resolution E-5124, p. 12.

administrators to independently track the retirement of RECs. MCE estimates those costs in the procurement forecast.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in two categories – (1) MCE labor costs; and (2) MCE direct costs for outreach and material.

3. BUDGET CAPS

Resolution E-4999 establishes a cap of 10% of the total budget for program administration costs and a cap of 4% of the total budget for ME&O costs, to apply beginning with each administrator's third program year.[6] Subsequently, in recognition that these programs may exceed the established caps because of their relatively small size, the time it takes to launch, and other factors, the Commission permitted PAs whose budgets exceed the established caps to submit a rationale supporting the exceedance in their Annual Budget Advice Letters (ABAL).[7] The ABAL was elevated from Tier 1 to Tier 2 to allow for additional review of this and other ABAL components.[8]

The 2025 budget forecast summarized above in Table 1 results in DAC-GT program administration budgets of 3% and ME&O budgets of 0%. As such, MCE does not require an adjustment to the program administration budget cap for DAC-GT for PY 2025.

4. BUDGET RECONCILIATION FOR PY 2023

MCE submitted a budget forecast for PY 2023 as a part of its 2023 Budget Request and Marketing, Education, and Outreach Plan in AL 58-E on February 1, 2022. The table below shows the forecasted and actual costs for PY 2023 per budget line item, as well as the true-up amount that will be carried forward to future program years.

[6] Resolution E-4999, p. 27.
[7] Resolution E-5125, p. 7.
[8] *Id.*

Table 2: MCE Budget Reconciliation for PY 2023

Category	DAC-GT			CS-GT		
	Forecast	Actual	**True-up (Actual - Forecast)**	Forecast	Actual	**True-up (Actual - Forecast)**
Generation Cost Delta	$ 988,083	$ 994,287	**$ 6,204**	$ -	$ -	**$ -**
20% Bill Discount	$ 280,035	$ 1,489,780	**$ 1,209,745**	$ -	$ -	**$ -**
Program Administration						
Program Management	$ 84,050	$ 10,125	**$ (73,925)**	$ 97,150	$ 3,062	**$ (94,088)**
Information Technology	$ 30,537	$ 7,343	**$ (23,194)**	$ 19,009	$ 1,531	**$ (17,478)**
Billing Operations	$ 76,735	$ 89,913	**$ 13,178**	$ 34,422	$ 1,531	**$ (32,891)**
Regulatory Compliance	$ 7,860	$ 27,582	**$ 19,722**	$ 7,860	$ 18,510	**$ 10,650**
Procurement	$ 26,815	$ 25,189	**$ (1,626)**	$ 31,093	$ 1,834	**$ (29,259)**
CCA Integration Costs	$ 2,430	$ 1,623	**$ (807)**	$ -	$ -	**$ -**
Subtotal Program Administration	**$ 228,427**	**$ 161,775**	**$ (66,652)**	**$ 189,534**	**$ 26,468**	**$ (163,066)**
Marketing, Education & Outreach						
Labor Costs	$ 21,615	$ 3,220	**$ (18,395)**	$ 59,605	$ 2,260	**$ (57,345)**
Outreach and Material Costs	$ 20,000	$ 6,248	**$ (13,752)**	$ 26,000	$ -	**$ (26,000)**
Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 25,000	$ -	**$ (25,000)**
Subtotal ME&O	**$ 41,615**	**$ 9,469**	**$ (32,146)**	**$ 110,605**	**$ 2,260**	**$ (108,345)**
Total	**$ 1,538,160**	**$ 2,655,310**	**$ 1,117,150**	**$ 300,139**	**$ 28,728**	**$ (271,411)**

5. 2025 BUDGET REQUEST

Based on the budget forecast for PY 2025 presented in Section 2 and the budget reconciliation for PY 2023 presented in section 4, MCE is requesting a total budget of $6,302,724 for the DAC-GT and CS-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2025

	DAC-GT	CS-GT	Total
Budget Carry-over from PY 2023	$ 1,117,150	$ (271,411)	**$ 845,739**
Budget Forecast for PY 2025	$ 5,456,985	$ -	**$ 5,456,985**
TOTAL	**$ 6,574,135**	**$ (271,411)**	**$ 6,302,724**

6. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports existing program capacity and customer enrollment numbers as of December 31, 2023 in Table 4 below. In PY 2023, enrolled customers were served with an interim solar resource, as discussed above.

Table 4: Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2023

Category	DAC-GT	CS-GT
Existing program capacity (MW)	4.646	0
Participating customers (#)	3,265	0

In Table 5, MCE reports forecasted capacity and customer enrollment for PY 2025. As noted above, MCE estimates that the dedicated project to serve existing DAC-GT will come online in early 2026. MCE plans to solicit a new project to serve the expanded DAC-GT capacity granted in D.24-05-065, but does not anticipate this project will come online during PY 2025. MCE plans to enroll additional customers under the expanded capacity using an interim resource until a new resource can be procured.

Table 5: Forecasted Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2025

Category	DAC-GT
Existing program capacity (MW)	4.646
Additional program capacity to be procured (MW)	3.609
Total program capacity (MW)	8.249
Estimated customer enrollment (#)	5,805

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 79-E

Tier Designation: 2

Subject of AL: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing): COMPLIANCE

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-05-065, E-4999, E-5125,

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 8/8/24

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Amulya Yerrapotu
Title: Policy Analyst
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: (925) 378-6729
Facsimile (xxx) xxx-xxxx:
Email: ayerrapotu@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

July 8, 2024

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 79-E

RE: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Pursuant to Ordering Paragraphs ("OP") 2 and 4 of Resolution E-4999,[1] OP 3 of Resolution E-5125,[2] and OPs 2 and 3 of D.24-05-065,[3] Marin Clean Energy ("MCE") hereby submits this Tier 2 Advice Letter ("AL") to submit the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT) program for the program year ("PY") 2025.

TIER DESIGNATION

This AL has a Tier 2 designation pursuant to OP 3 of Resolution E-5125.

EFFECTIVE DATE

Pursuant to G.O. 96-B, MCE requests that this Tier 2 AL become effective on August 8, 2024, which is 30 calendar days from the date of this filing.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved D.18-06-027, adopting two new community solar programs to promote the use of

[1] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. MCE's implementation Advice Letter, MCE AL 42-E/E-A/E-B was approved in Resolution E-5124, which brought MCE under the same program rules and reporting structure applicable to the IOUs.
[2] OP 3 of Resolution E-5125 directed that DAC-GT and CS-GT Annual Budget Advice Letters are to be submitted as Tier 2 ALs to allow for additional review and oversight.
[3] OP 2 of D.24-05-065 discontinues the CS-GT program and directs program administrators to transfer remaining capacity, customers, and programs into the DAC-GT program. OP 3 of D.24-05-065 makes several modifications to the DAC-GT program, which are reflected in this budget submission.

renewable generation among residential customers in disadvantaged communities ("DACs"),[4] as directed by the California Legislature in Assembly Bill ("AB") 327 (Perea), Stats. 2013, ch 611. The DAC-GT and the CS-GT programs offer 100% solar energy to eligible customers and provide a 20% discount on the electric portion of the utility bill.

D.18-06-027 allows Community Choice Aggregators ("CCAs") to develop their own DAC-GT and CS-GT programs, and states that CCAs that elect to offer DAC-GT and CS-GT must abide by all rules and requirements adopted in that decision.[5] Pursuant to OP 17 of D.18-06-027, MCE filed its Implementation AL (MCE AL 42-E) on May 7, 2020. The Commission approved AL 42-E in Resolution E-5124, issued April 15, 2021.

Resolution E-4999 from May 2019 approved the investor-owned utilities' ("IOUs") implementation ALs for the DAC-GT and CS-GT programs and established the budgeting procedures and timelines for the programs. The Resolution sets the deadline for submitting annual DAC-GT and CS-GT program budget requests and ME&O plans for the upcoming PY by February 1st of each year.[6] Furthermore, the Resolution specifies that Program Administrators must reconcile prior year budget forecasts and expenditures in their annual budget requests.[7] On December 4, 2023, MCE, as a part of the Joint CCAs, requested a two-month extension of the budget AL until April 1, 2023. On January 11, 2024, MCE, as a part of the Joint CCAs, amended the extension request to align with the IOUs, requesting an extension until May 1, 2024, or 30 days after the issuance of the Final Decision in proceeding A.22-05-022, whichever is later. On January 24, 2024, the Joint CCAs' extension request was granted. The Final Decision in proceeding A.22-05-022 was issued on June 7, 2024.[8]

On May 30, 2024, the CPUC approved D.24-05-065, discontinuing the CS-GT program and approving a number of modifications to the DAC-GT program. The DAC-GT program modifications pertaining to CCA program administrators include: modifying project siting requirements, increasing program capacity, allowing the voluntarily inclusion of storage in projects, ordering the cost containment cap to be updated, changing the budget advice letter deadline to April 1st, and removing the Green-e certification requirement.

Per D.18-06-027, the budget requirements outlined in Resolution E-4999 apply to participating CCAs as well. The submission and approval of this budget AL is the prerequisite to having the DAC-GT and CS-GT budgets included in the IOUs' Energy Resource Recovery Account ("ERRA") Forecast in June each year. The ERRA Forecast in turn enables cost recovery of the programs. Therefore, MCE is submitting this advice letter to ensure timely cost recovery for its programs.

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[4] DACs are defined under Resolution E-5212 as communities that are identified in version 3.0 or any subsequent version of CalEnviroScreen as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. Resolution E-5212 also expands program eligibility to include California Indian Country.
[5] D.18-06-027, p. 104, OP 17.
[6] Resolution E-4999, OP 2.
[7] Resolution E-4999, OP 4.
[8] D.24-05-065

PURPOSE

MCE hereby submits the budget request for PY 2025 for the DAC-GT program. Per Resolution E-4999, the budget request includes both the budget reconciliation for the previous PY (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). Because D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a project for the CS-GT program, MCE does not include CS-GT in the PY 2025 budget forecast. However, MCE continues to include CS-GT program costs in the PY 2023 budget reconciliation. In summary, MCE requests a total budget of $6,791,967 for the DAC-GT program for PY 2025, including PY 2023 CS-GT reconciliation costs. Additional details can be found in Appendix A.

Once the Commission approves MCE's budget request, PG&E will be responsible for including the total budget request for MCE's DAC-GT program in the 2025 ERRA Forecast filing.[9] Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT balancing account. PG&E will then transfer program funds to MCE as determined in Resolution E-5124.[10]

In addition to the budget request, MCE submits its updated ME&O plan for PY 2025 as Appendix B.

CONCLUSION

MCE respectfully requests the Commission approve the budgets proposed herein and direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms set forth in Resolution E-5124. MCE also requests approval of its ME&O plan for 2025.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002 and Application A.22-05-022.

For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

Anyone wishing to protest this advice letter filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests must be submitted to:

CPUC, Energy Division

[9] D.22-01-023, p. 28, OP 3. Modifies the due date for PG&E to file this annual Application to May 15, 2023. Because D.24-05-065 was not voted on until May 30, 2024, pushing this advice letter filing to July 8th, 2024 PG&E may need to include an updated budget in its October ERRA forecast update.
[10] Resolution E-5124, p. 10.

Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter shall be sent electronically to the attention of:

Amulya Yerrapotu
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: ayerrapotu@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Amulya Yerrapotu at (925) 378-6729 or by electronic mail at ayerrapotu@mcecleanenergy.org.

/s/ Amulya Yerrapotu

Amulya Yerrapotu
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MARIN CLEAN ENERGY
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Telephone: (925) 378-6729
Email: ayerrapotu@mcecleanenergy.org

Appendices

Appendix A: PY 2025 Budget Request
Appendix B: PY 2025 ME&O Plan

cc: Service List for R.14-07-002 and A.22-05-022

Budget Forecast for the Disadvantaged Communities Green Tariff Program for Program Year 2025

Proposed by Marin Clean Energy

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1. BACKGROUND

MCE is a program administrator (PA) of the Disadvantaged Communities (DAC) Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs. Per Resolution E-4999, annual program budgets must be presented by program and include the following budget line items:[1]

1. Generation cost delta, if any;[2]
2. 20 percent bill discount for participating customers;
3. Program administration costs: [3]
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance;
    e. Procurement;
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only).

In this program budget, MCE includes both the budget reconciliation for the previous program year (PY) (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). As D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a CS-GT project, MCE does not include CS-GT program costs for PY 2025, and only includes CS-GT costs in the budget reconciliation for PY 2023, but does not include CS-GT program costs for PY 2025.

In addition to budget reconciliation and forecast, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on:

1. Existing solar generation capacity at previous PY's close (i.e., December 31, 2023);
2. Forecasted solar generation capacity under contract for procurement in the upcoming PY;
3. Customers served at previous PY's close (i.e., December 31, 2023); and

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[1] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to MCE Advice Letter 42-E filed on May 7, 2020.

[2] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate."

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4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission's (CPUC or Commission) Energy Division staff directly:

1. Calculation of the generation cost delta;
2. Calculation of the 20% bill discount to participating customers.

2. BUDGET FORECAST FOR PY 2025

For PY 2025, MCE forecasts a total budget of $5,946,227 for the DAC-GT program. This budget forecast accounts for the program modifications established in D.24-05-065, including discontinuing the CS-GT program and rolling unused capacity into the DAC-GT program, increasing DAC-GT program capacity, and removing the Green-e certification requirement. A detailed budget forecast for each program by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PY 2025

Category	DAC-GT
Generation Cost Delta	$ 2,446,213
20% Bill Discount	$ 3,310,666
Program Administration	
Program Management	$ 22,820
Information Technology	$ 11,617
Billing Operations	$ 98,868
Regulatory Compliance	$ 18,996
Procurement	$ 15,690
Subtotal Program Administration	**$ 167,991**
Marketing, Education & Outreach	
Labor Costs	$ 6,357
Outreach and Material Costs	$ 15,000
Subtotal ME&O	**$ 21,357**
Total	**$ 5,946,227**

MCE provides a brief description of each of the budget line items below.

Generation Cost Delta
To date, MCE has been using interim solar generation resources to support the DAC-GT program while it is procuring a dedicated solar facility for the program. On June 20, 2022, the Commission

granted MCE's request to approve its dedicated DAC-GT power purchase agreement (PPA).[4] On November 11, 2024, the Commission approved MCE's first request to amend its dedicated DAC-GT PPA. On June 19, 2024, the Commission approved MCE's second request to amend its dedicated DAC-GT PPA. The new dedicated solar generation facility is expected to come online in early 2026. As such, the DAC-GT generation cost delta budget forecast for 2025 is based on the PPA price of the current interim solar generation resource, compared to the costs of serving customers under MCE's residential base tariff, the "Light Green" tariff.

Decision 24-05-065 approves a 50% expansion of MCE's DAC-GT program capacity. Decision 24-05-065 also rolls any unused CS-GT capacity into MCE's DAC-GT program. MCE's DAC-GT program now has a total capacity of 8.249 MW. MCE plans to enroll customers using an interim resource as it works to procure a resource to serve the remaining program capacity. MCE anticipates using the existing DAC-GT interim resource for this purpose.

20 Percent Bill Discount

As set forth in Resolution E-5124, MCE calculates the 20% bill discount on both the generation and transmission and distribution (T&D) portion of the electric bill for participating customers. The bill discount is then fully included on the generation portion of customer bills, i.e., the discount reduces the electric generation costs of a customer's bill only.[5] MCE then recovers these program costs via this budget AL filing.

In PY 2025, MCE expects to have approximately 5,805 customers enrolled in the DAC-GT program. D.24-05-065 expands MCE's DAC-GT program capacity by 3.609 MW. MCE estimates that it will be able to serve 2,540 customers with this new capacity, in addition to the existing 3,265 customers currently served by existing program capacity. MCE plans to enroll customers using an interim resource as it works to procure a new resource to serve the remaining program capacity. The PY 2025 forecast for the 20 percent bill discount is based on the actual average monthly bill discount provided to participating customers in 2023, with a 25% increase to account for forecasted increases in electricity rates. Future customers enrolled under the expanded capacity are assumed to have the same usage as existing customers.

Program Administration Costs

Program administration includes program development, management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations cover costs for ongoing billing operations and customer support, including the costs of MCE's third-party billing provider. While D.24-05-065 directs PG&E to provide a cost estimate for implementing an automated billing solution, it is uncertain whether such a solution will be implemented. As such, for the time being, MCE assumes that billing costs will remain as they are now. Regulatory Compliance covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, ongoing contract management, as well as annual renewable energy credit (REC) retirement and compliance functions. D.24-05-065 removes the Green-e certification requirement, instead ordering program

[4] See Disposition of MCE AL 63-E, MCE Disadvantaged Communities Green Tariff Program 2022 Power Purchase Agreement Approval.

[5] Resolution E-5124, p. 12.

administrators to independently track the retirement of RECs. MCE estimates those costs in the procurement forecast.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in two categories – (1) MCE labor costs; and (2) MCE direct costs for outreach and material.

3. BUDGET CAPS

Resolution E-4999 establishes a cap of 10% of the total budget for program administration costs and a cap of 4% of the total budget for ME&O costs, to apply beginning with each administrator's third program year.[6] Subsequently, in recognition that these programs may exceed the established caps because of their relatively small size, the time it takes to launch, and other factors, the Commission permitted PAs whose budgets exceed the established caps to submit a rationale supporting the exceedance in their Annual Budget Advice Letters (ABAL).[7] The ABAL was elevated from Tier 1 to Tier 2 to allow for additional review of this and other ABAL components.[8]

The 2025 budget forecast summarized above in Table 1 results in DAC-GT program administration budgets of 3% and ME&O budgets of 0%. As such, MCE does not require an adjustment to the program administration budget cap for DAC-GT for PY 2025.

4. BUDGET RECONCILIATION FOR PY 2023

MCE submitted a budget forecast for PY 2023 as a part of its 2023 Budget Request and Marketing, Education, and Outreach Plan in AL 58-E on February 1, 2022. The table below shows the forecasted and actual costs for PY 2023 per budget line item, as well as the true-up amount that will be carried forward to future program years.

[6] Resolution E-4999, p. 27.
[7] Resolution E-5125, p. 7.
[8] *Id.*

Table 2: MCE Budget Reconciliation for PY 2023

Category	DAC-GT			CS-GT		
	Forecast	Actual	**True-up (Actual - Forecast)**	Forecast	Actual	**True-up (Actual - Forecast)**
Generation Cost Delta	$ 988,083	$ 994,287	**$ 6,204**	$ -	$ -	**$ -**
20% Bill Discount	$ 280,035	$ 1,489,780	**$ 1,209,745**	$ -	$ -	**$ -**
Program Administration						
Program Management	$ 84,050	$ 10,125	**$ (73,925)**	$ 97,150	$ 3,062	**$ (94,088)**
Information Technology	$ 30,537	$ 7,343	**$ (23,194)**	$ 19,009	$ 1,531	**$ (17,478)**
Billing Operations	$ 76,735	$ 89,913	**$ 13,178**	$ 34,422	$ 1,531	**$ (32,891)**
Regulatory Compliance	$ 7,860	$ 27,582	**$ 19,722**	$ 7,860	$ 18,510	**$ 10,650**
Procurement	$ 26,815	$ 25,189	**$ (1,626)**	$ 31,093	$ 1,834	**$ (29,259)**
CCA Integration Costs	$ 2,430	$ 1,623	**$ (807)**	$ -	$ -	**$ -**
Subtotal Program Administration	**$ 228,427**	**$ 161,775**	**$ (66,652)**	**$ 189,534**	**$ 26,468**	**$ (163,066)**
Marketing, Education & Outreach						
Labor Costs	$ 21,615	$ 3,220	**$ (18,395)**	$ 59,605	$ 2,260	**$ (57,345)**
Outreach and Material Costs	$ 20,000	$ 6,248	**$ (13,752)**	$ 26,000	$ -	**$ (26,000)**
Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 25,000	$ -	**$ (25,000)**
Subtotal ME&O	**$ 41,615**	**$ 9,469**	**$ (32,146)**	**$ 110,605**	**$ 2,260**	**$ (108,345)**
Total	**$ 1,538,160**	**$ 2,655,310**	**$ 1,117,150**	**$ 300,139**	**$ 28,728**	**$ (271,411)**

5. 2025 BUDGET REQUEST

Based on the budget forecast for PY 2025 presented in Section 2 and the budget reconciliation for PY 2023 presented in section 4, MCE is requesting a total budget of $6,791,967 for the DAC-GT and CS-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2025

	DAC-GT	CS-GT	Total
Budget Carry-over from PY 2023	$ 1,117,150	$ (271,411)	**$ 845,739**
Budget Forecast for PY 2025	$ 5,946,227	$ -	**$ 5,946,227**
TOTAL	**$ 7,063,378**	**$ (271,411)**	**$ 6,791,967**

6. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports existing program capacity and customer enrollment numbers as of December 31, 2023 in Table 4 below. In PY 2023, enrolled customers were served with an interim solar resource, as discussed above.

Table 4: Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2023

Category	DAC-GT	CS-GT
Existing program capacity (MW)	4.646	0
Participating customers (#)	3,265	0

In Table 5, MCE reports forecasted capacity and customer enrollment for PY 2025. As noted above, MCE estimates that the dedicated project to serve existing DAC-GT will come online in early 2026. MCE plans to solicit a new project to serve the expanded DAC-GT capacity granted in D.24-05-065, but does not anticipate this project will come online during PY 2025. MCE plans to enroll additional customers under the expanded capacity using an interim resource until a new resource can be procured.

Table 5: Forecasted Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2025

Category	DAC-GT
Existing program capacity (MW)	4.646
Additional program capacity to be procured (MW)	3.609
Total program capacity (MW)	8.249
Estimated customer enrollment (#)	5,805

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for Program Year 2025

Proposed by Marin Clean Energy

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1. PURPOSE AND GOALS

MCE will develop and implement a targeted customer marketing, education, and outreach (ME&O) campaign under the Disadvantaged Communities Green Tariff (DAC-GT) program to ensure potential customers in disadvantaged communities (DACs) are aware of the benefits from the program.

Eligible customers for DAC-GT will be identified and automatically enrolled in the program by MCE. Hence, no customer recruitment for program participation is required.

MCE's ME&O strategy for the DAC-GT program has three main goals:

1. Notify DAC-GT customers that their account has been automatically enrolled in the program;
2. Provide information (i.e., FAQs) about the program; and
3. Notify DAC-GT customers if they no longer meet eligibility criteria for the program (i.e., moved, installed solar, or no longer enrolled in CARE or FERA) and provide instructions on how to continue their program participation (if applicable).

2. GUIDING PRINCIPLES

MCE is committed to developing diverse and culturally appropriate communication strategies to ensure that stakeholders can participate in decisions and actions that impact their communities. As such, MCE commits to the following guiding principles throughout the ME&O engagement process for the DAC-GT program. MCE aims to:

- Achieve diverse and meaningful engagement that reflects the demographics of DAC communities to ensure equitable outreach across race, income and age barriers.

3. TARGET AUDIENCE

Upon the launch of the DAC-GT program in 2021, MCE automatically enrolled eligible customers who live in one of the top 10% of DAC census tracts statewide, as defined by CalEnviroScreen 3.0, and who reside within MCE's service area. Priority was given to customers who made an effort to pay, as defined by making at least four full or partial payments in the preceding eight months. With the expanded capacity of the DAC-GT program, MCE will enroll additional customers as identified by CalEnviroScreen 4.0 in the following order:

1. Customers who live in one of the top 25% of DAC census tracts and are enrolled in the Arrearage Management Program (category 1);
2. Customers who live in one of the top 25% of DAC census tracts and are in arrears (category 2); and then
3. All other customers who live in one of the top 25% of DAC census tracts (category 3).

If there is insufficient program capacity to enroll all customers in a category under the DAC-GT program, customers from the eligible category will be randomly selected for program enrollment. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist based on the above criteria as appropriate.

Figure 1 shows the list of eligible census tracts for DAC-GT auto-enrollment.

Figure 1. Qualifying Neighborhoods in MCE Service Area for DAC-GT Auto-Enrollment

75% CalEnviroScreen 4.0 Score			
Census Tract	**California County**	**ZIP**	**Nearby City (to help approximate location only)**
6013305000	Contra Costa	94509	Antioch
6013306002	Contra Costa	94509	Antioch
6013306003	Contra Costa	94509	Antioch
6013307102	Contra Costa	94509	Antioch
6013309000	Contra Costa	94565	Pittsburg
6013310000	Contra Costa	94565	Pittsburg
6013311000	Contra Costa	94565	Pittsburg
6013312000	Contra Costa	94565	Pittsburg
6013314102	Contra Costa	94565	Pittsburg
6013314103	Contra Costa	94565	Pittsburg
6013314104	Contra Costa	94565	Pittsburg
6013314200	Contra Costa	94565	Pittsburg
6013327000	Contra Costa	94520	Concord
6013336201	Contra Costa	94520	Concord
6013358000	Contra Costa	94572	Rodeo
6013365002	Contra Costa	94801	Richmond
6013366002	Contra Costa	94806	San Pablo
6013368001	Contra Costa	94806	San Pablo
6013368002	Contra Costa	94806	San Pablo
6013369001	Contra Costa	94806	San Pablo
6013375000	Contra Costa	94801	Richmond
6013376000	Contra Costa	94801	Richmond
6013377000	Contra Costa	94801	Richmond
6013379000	Contra Costa	94804	Richmond
6013380000	Contra Costa	94804	Richmond
6013381000	Contra Costa	94804	Richmond
6013382000	Contra Costa	94804	Richmond
6013392200	Contra Costa	94806	San Pablo
6095250701	Solano	94590	Vallejo
6095250801	Solano	94592	Vallejo

6095250900	Solano	94590	Vallejo
6095251000	Solano	94590	Vallejo
6095251600	Solano	94590	Vallejo
6095251802	Solano	94589	Vallejo
6095251803	Solano	94589	Vallejo
6095251901	Solano	94589	Vallejo
6013314103	Contra Costa	94565	Pittsburg
6013314102	Contra Costa	94565	Pittsburg
6013306002	Contra Costa	94509	Antioch

4. ME&O TACTICS AND STRATEGIES

MCE will leverage the communications and media content originally developed to promote DAC-GT, including direct mailers, email, and webpage.

5. METRICS TRACKING

MCE will use a variety of metrics to evaluate the effectiveness of each effort. The primary measure of effectiveness used will be the number of customers reached, which will be measured by:

- Number of customers enrolled based on auto enrollment criteria;
- Number of customers found to be ineligible for the program based on eligibility criteria;
- Number of customers opting to cancel program participation; and
- Number of customers to be enrolled from the waitlist based on the capacity provided through the total sum of all aforementioned attributes.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

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July 10, 2024

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I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC" or "Commission") *Administrative Law Judge's Ruling Directing Response to Questions Regarding Implementation of Decision 24-05-065* dated June 5, 2024 ("ALJ Ruling" or "Ruling"), Ava Community Energy, Clean Power Alliance of Southern California, the City and County of San Francisco, acting by and through its Public Utilities Commission, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, San Diego Community Power, San Jacinto Power, and San José Clean Energy (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Opening Comments.

The Joint CCAs appreciate the Commission's aim to expeditiously resolve implementation issues associated with the modified Disadvantaged Communities Green Tariff ("DAC-GT") and the new Community Renewable Energy ("CRE") programs as adopted by

Decision ("D.") 24-05-065, *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program* ("the Decision"). The Joint CCAs support the Commission's goal of furthering the development of local, front-of-the-meter ("FTM") distributed energy resources ("DERs") – community solar and storage resources in particular – and look forward to collaborating with the Commission on developing the details that would allow interested Community Choice Aggregators ("CCAs") to offer a CCA-led CRE Program. As noted in the Ruling and the Decision, the record does not contain specifics for CCA participation, and there are open questions associated with which tariffs and processes should be in place to enable interested CCAs to participate in the CRE Program.[1] In these comments, the Joint CCAs outline the cornerstones of a proposed CRE Program that can incorporate both investor-owned utility ("IOU") and CCA tariffs. While the Joint CCAs propose to largely align the CRE Program between IOU and CCA administrators, there are a few instances where program rules may differ (as further outlined below).

The Joint CCAs' comments are structured in three sections. Section II provides a summary of the Joint CCAs' CRE Program proposal and highlights concerns regarding the financial viability of the CRE Program with current funding allocations. Section III answers specific questions in the ALJ Ruling regarding the CRE Program, providing additional details regarding the Joint CCAs' CRE Program proposal as it relates specifically to developer compensation and the "subscriber revenue share" (referred to hereafter as "customer incentives"). Finally, Sections IV through VI respond to select Ruling questions regarding the modification of the DAC-GT program.

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[1] *See* D.24-05-065 at 148 ("As CCAs are permitted to participate in the new community renewable energy program, the foundational tariffs will need to be revised to accommodate this participation. At this time, the record does not contain the specifics for CCA participation"); *see also* Ruling at 7 (requesting comment on which process should be employed to enable CCA participation).

II. SUMMARY OF CCA CRE PROGRAM PROPOSAL

A. The New CRE Program Must Equally Incorporate IOU and CCA Tariffs

The Joint CCAs support greater development of distributed FTM resources, and appreciate the opportunity to provide feedback on the new CRE Program to ensure that interested CCAs will be able to participate. The Decision specifies that the new CRE Program shall be based on one of the existing IOU tariffs that are compliant with the federal Public Utility Regulatory Policies Act ("PURPA"), such as the Renewable Market Adjusting Tariff ("ReMAT") and Standard-Offer-Contract ("SOC") tariffs.[2] However, as these are IOU-specific tariffs, the Commission also notes in the Decision that "the foundational tariffs will need to be revised to accommodate" CCA participation.[3] The Joint CCAs propose that both IOUs and CCAs use SOCs as foundational tariffs for the CRE Program. Specifically, the Joint CCAs propose to offer a SOC tariff that incorporates the IOUs' PURPA wholesale tariffs but which is governed by CCA tariff rules and principles. As noted above, the Joint CCAs recommend that program rules and requirements should largely be aligned between IOUs and CCAs offering the CRE Program, as is customary under the existing DAC-GT programs. This would ensure consistency between the various CRE Programs and would minimize confusion among customers and developers. As such, the Joint CCA proposal illustrated below would be consistent across both IOU and CCA program administrators with limited exceptions.

The Joint CCAs provide the following proposal as the basic underlying structure of the CRE Program, detailing the program's contract structure and project requirements. Further details regarding developer compensation and customer incentives are provided in Section III in response to the ALJ Ruling questions.

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[2] D.24-05-065 at 168, Ordering Paragraph ("OP") 1(a).

[3] *Id*. at 148.

i. Proposed CRE Contract Structure and Project Requirements

Similar to the IOUs, the Joint CCAs propose that interested CCAs would offer SOCs under the CRE Program in which a developer signs a power purchase agreement ("PPA") directly with the load serving entity ("LSE") (i.e., in this case, the CCA) for a 20-year delivery term. The 20-year delivery term is recommended to enable subscribing customers to meet Title 24 requirements by enrolling under a CRE project.

The Joint CCAs believe the CRE Program should be based on SOCs because this contract structure allows the developers insight into PPA prices, which in turn helps them assess the feasibility of project development. One of the hurdles the Joint CCAs have encountered under the DAC-GT and Community Solar Green Tariff ("CSGT") programs has been that developers are uncertain about the cost cap for PPAs because that information is confidential. The Joint CCAs understand that developers may choose not to participate in DAC-GT or CSGT solicitations due to the perception that the prices for their projects may be too high. A set PPA price under a SOC construct would remove this uncertainty. This construct would also reduce PPA negotiations and bid pricing reviews, leading to program administration efficiencies and price consistency for customers throughout the state.

As detailed further in response to Question 1 in Section III below, the Joint CCAs are proposing that the CRE Program PPA price be based on several components, including a PPA base payment and additional price adders. Consistent with the Decision, the Joint CCAs propose that the PPA base payment would be based on the PURPA avoided costs for both IOU and CCA projects,[4] with additional "adders" provided to appropriately value the local DERs. While the

[4] *Id*. at 125 ("The adopted community renewable energy program will compensate generating resources based on the PURPA avoided costs of the facility…[T]he Commission will use its own method to determine the avoided cost of the generating resource, with PURPA guidance.")

Joint CCAs are amenable to adopting the PURPA avoided costs as the base PPA price under the CRE Program, it must be highlighted that CCAs do not fall under PURPA compliance and CCA avoided generation costs are likely to differ from the IOUs' avoided costs.

The CRE Program resources would consist of solar, or solar plus storage, projects.[5] The Joint CCAs propose certain locational requirements to support *community-based* solar or solar plus storage projects, and to ensure that projects are located in areas where the load (or customer) is located. In the case of a CCA offering the CRE Program, one could argue that the resource is implicitly "local" if it is located in a CCA's (more geographically limited) service area and will only serve CCA customers. However, the same is not necessarily true for IOU projects due to the vast size of the IOUs' service territories.[6] For these reasons, the Joint CCAs propose that CRE projects must be located within 50 miles of subscribing customers for both IOU and CCA-led CRE Programs (or vice versa, subscribing customers must be located within 50 miles of the CRE resource). The Joint CCAs are open to considering other locational requirements as proposed by stakeholders in response to this Ruling.

Additionally, CRE resources must be integrated into the California Independent System Operator ("CAISO") market. It is essential that resources under the program can receive resource adequacy ("RA") credit. However, RA credits are only possible if the resource can receive deliverability status, which has been an observed barrier for distributed resources because the deliverability allocation process is an ill fit for projects of this type. If it is cost prohibitive or otherwise not feasible for the resource to get deliverability, the Commission should work with

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[5] *Id*. at 169, OP 1(i) ("Storage – The community renewable energy program tariff shall allow for co-located solar and storage.")

[6] Pacific Gas & Electric ("PG&E"), for example, could technically locate a resource in Fresno and serve customers in Humboldt County if the locational requirement under the CRE Program would be the LSE's service area, thereby defeating the purpose of a *community* renewable energy program.

the California Energy Commission ("CEC") to allow a resource to get RA credit as a load modifier via the LSE's year-ahead RA forecast by virtue of reducing the LSE's RA obligation.[7] Such coordination would preferably occur prior to contracting, to provide LSEs certainty that they would receive RA credit for resources under the program and to minimize redundant RA costs for customers.

The Joint CCAs propose a minimum project size of 500 kW and a maximum project size of 5 MW under both the IOU and CCA CRE Programs.[8] As further detailed below, the current allocated funding amount will effectively limit the CRE Program to around 50 MW of capacity, and the limitation of the project size can ensure that more distributed resources are being built under the program to benefit more localized communities. Furthermore, it should be a primary goal of the program to site resources in areas where load is located, thereby reducing the likelihood of land availability for large resources. For those reasons, the Joint CCAs recommend a smaller maximum system size than the one proposed in the Decision.

Contrary to Southern California Edison's ("SCE") proposal, the Joint CCAs do not recommend that projects *must* be located in capacity constrained areas.[9] The Joint CCAs propose

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[7] The Net Value Billing Tariff ("NVBT") proposal previously included a proposal for resources as load modifiers on the CEC year-ahead RA forecast which the Joint CCAs objected to. However, those concerns related to the fact that only LSEs file year-ahead RA forecasts with the CEC, and under the NVBT proposal, the LSEs would not have held the contract with the resource developer. Under the CCA CRE Program, the LSE would be the counterparty on the resource and would, therefore, have more insight into the resource. The Joint CCA acknowledge that there would be many implementation details associated with this proposal, including coordination with the CEC and, therefore, offer this as a suggestion for conversation moving forward.

[8] *See* D.24-05-065 at 156 (The Joint CCAs are proposing a maximum project size under the 20 MW limit set by the Decision); *See also* Cal. Code Regs, tit. 24, pt. 1 §10-115(a)(7) ("The community shared solar electric generation system and/or community shared battery storage system shall not be served by an individual source larger than 20 MW.").

[9] *See* D.24-05-065 at 79 ("Other parameters of SCE's proposal include a maximum facility size of three megawatts, a capacity constrained site location requirement, a combine solar and storage requirement (allowing for Renewable Energy Credits), and a requirement that storage dispatch rights be provided to the contracting utility.").

to offer a PPA adder to projects located in capacity constrained areas but recommend against *requiring* project siting in those areas. This requirement would limit project siting too much and would require IOU analyses which have been unavailable in the past.[10]

Finally, in accordance with Assembly Bill 2316 and the Decision, developers must demonstrate that all projects shall comply with the prevailing wage requirement,[11] and must further demonstrate to the CEC that the proposal complies with Section 10-115 of the California Building Code.[12]

ii. CRE Customer Eligibility

Each LSE would enroll eligible customers in their respective CRE Programs.[13] Per the Decision, all residential customers (i.e. low-income and non-low-income), as well as small commercial customers, will be eligible to enroll as subscribers to the CRE Program.[14] In accordance with Assembly Bill 2316 and the Decision, the Joint CCAs propose that at least 51% of each project's capacity under the CRE program must be subscribed by low-income customers.[15] Low-income customers are defined as individuals or households who qualify for the California Alternate Rates for Energy ("CARE") program, Family Electric Rate Assistance ("FERA") program, CalFresh, Supplemental Nutrition Assistance Program ("SNAP"), or the Low-income Heating Energy Assistance Program ("LIHEAP"), or reside in an underserved

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[10] *See generally* Rulemaking 21-06-017 Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future ("High DER Rulemaking") including discussions about locating distributed resources in areas of grid constraint.

[11] D.24-05-065 at 169, OP 1(h).

[12] *Id*. at 168-169, OP 1(f).

[13] Customers will be subscribed to a portion of a CRE project based on their previous 12-months load. If only partial or no previous load is available, customer load can be estimated. The same process is used for DAC-GT customer enrollment.

[14] Technically, OP 1(d) of D.24-05-065 states that "*All [emphasis added]* customers will be eligible to enroll as subscribers to the tariff" (i.e. residential and non-residential customers alike). See D.24-05-065 at 168. However, the Decision's text at 119 implies that only residential customers, and small commercial customers, are the intended participants under the program.

[15] D.24-05-065 at 169, OP 1(g).

community which includes low-income communities as defined in Health & Safety Code Section 39713, communities within the 25% most disadvantaged communities according to the CalEnviroScreen, and communities located on tribal lands.[16]

The remaining 49% of a project's capacity is not limited to a certain customer type but, as noted in the Decision, it is recommended that this capacity would focus on enrolling non-low-income customers who rent or lease.[17]

Per the Decision, low-income customers would be auto-enrolled under the CRE Program. The Joint CCAs further discuss auto-enrollment provisions in response to Question 9 in Section III below.

B. Any CRE Program Implemented by the Commission Must Take Into Account Current Funding Limitations

Some parties have raised the concern that the current funding expected to be available for the CRE Program is too limited to create an impactful program.[18] The Joint CCAs agree. The Commission has noted in the Decision that it will set aside certain funding for the CRE Program, namely $33 million appropriated to the Commission by Assembly Bill 102 (2023) for community energy renewable program usage and storage-backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding (collectively referred to herein as "CRE Funding").[19] California was awarded $249,800,000 in

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[16] *See* Pub. Util. Code Section 769.3(a)(3).

[17] D.24-05-065 at 118.

[18] *See* Comments of Cypress Creek Renewables, LLC on the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 12; Clean Coalition Comments on Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 3; Comments of The Solar Energy Industries Association on Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 14.

[19] D.24-05-064 at 118 (citing AB 102, Budget Act of 2023, Section 244 appropriated $33 million to the Commission with additional requirements.)

Solar for All funding but it is not clear how much of that funding will be set aside for the CRE Program.[20] If an estimated $100 million is set aside from the EPA's Solar for All funding, in total, the CRE Program would have a statewide budget of $133 million.

While the Decision does not establish a program capacity cap, the program's capacity is implicitly limited by the funding available for the program. As is discussed further below in Section III in response to Questions 1- 4, the CCAs are proposing that the CRE Funding would pay for two core components of the program: (1) the customer incentives (i.e. revenue share) paid to participating low-income customers and (2) the "Community Solar Adder", an adder contributing to the overall PPA price paid to the developer. The Joint CCAs would also expect CRE Funding to cover administrative costs of the CRE Program. This is in alignment with the DAC-GT program, where ratepayer funds are used to cover (1) the bill discount paid to participating low-income customers, (2) the "above-market generation costs" of the solar (and storage) resource, *and* (3) administrative and marketing, education and outreach ("ME&O") costs of the program.

Even if CRE Funding were to only cover customer incentives and the Community Solar Adder, the current funding allocation of an estimated $133 million would only allow for approximately 50 MW of statewide program capacity based on the estimated pricing assumptions that the Joint CCAs use in Table 1 below.[21] The Joint CCAs would like to highlight

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[20] *See* Solar for All Selected Applicants, available at: https://www.epa.gov/greenhouse-gas-reduction-fund/solar-all; *See also* D.24-05-065 at 118 fn 327 (stating that "some portion" of the funds would support the community renewable energy program).

[21] In the example outlined below, the CRE Funding would cover $20/MWh for the Community Solar Adder and $2/kW-month for the Community Storage Adder for a blended rate of $36.44/MWh. The CRE Funding would also cover $52.52/MWh for the CRE solar + storage Incentive Rate for 50% of customers (only low-income) leading to total costs of $62.7/MWh. $133 million in funding can cover around 106,000MWh annually (over a 20-year contract period), and if one assumes an even split of MWhs between the solar and the storage resource, the CRE Funding could cover around 20MW in solar and 36MW in storage resource for a combined program capacity of 56MW.

that such a limited program cap (and estimated funding amount) may be insufficient to incentivize the administrative effort necessary to develop a new community renewable energy program in California. As noted above, the Joint CCAs support the development of local FTM DERs but also want to caution that adequate funding must be available to make the program successful (if not feasible). Commissioner Houck also acknowledged the current funding limitations for the CRE Program and the risks it poses to the success of the program in her dissent to the recent Decision.[22] The Joint CCAs strongly recommend that the Commission take these funding limitations into consideration when further developing the CRE program and consider potential avenues for additional funding that may be available for this program.

III. RESPONSES TO RULING QUESTIONS: NEW COMMUNITY RENEWABLE ENERGY PROGRAM

A. Revenue Share and Bill Credits

1. *The new community renewable energy program is designed to deliver value through two streams of funding: (i) the stable but moderately adjusting compensation from wholesale tariffs and (ii) the external, nonratepayer, funding or "adder" that is managed through investor-owned utility (Utility) balancing accounts. How should these streams of funding be applied to provide both developer compensation and subscriber savings or revenue share (i.e., percentage split of total revenue from a project between the developer or generator account and benefiting or subscriber accounts)?*

The Joint CCAs make the following proposal regarding the structure of the developer compensation and the subscriber's "incentive"[23] for the CRE Program (including IOU and CCA tariffs). These proposals are based on SCE's proposal provided in SCE's Opening Comments to the *Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value*

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[22] *See* Concurrence and Dissent of Commissioner Darcie L. Houck as to the Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program.

[23] As described above, the Joint CCAs call the subscriber's "revenue share" an "incentive" as it more appropriately describes the form of payment the customer receives. Following SCE's proposal, the customer does not receive a share of the projects revenue (which would be CAISO revenues), but instead the customer incentive is calculated as a percentage of the PPA price.

Benefit Tariff Proposal, dated November 6, 2024 , as well as the requirements of the Decision with slight proposed modifications.

i. Developer Compensation

The Joint CCAs agree with SCE's proposal that developers be paid based on the project's PPA price.[24] Importantly, the PPA would braid several different value streams together to ensure that the developers are encouraged to develop local, community-based solar, or solar plus storage, projects. The Joint CCAs propose that the PPA price offered under the CRE Program be comprised of three core elements: (i) a base payment, (ii) a Community Solar Adder, and (iii) a Grid Capacity Adder. Additionally, for the *CCA* CRE Programs specifically, an individual CCA has the discretion to add a fourth element, a "Community Goals Adder." The following describes each of the proposed PPA elements in more detail.

Base Payment

The base payment should be consistent across IOU and CCA CRE projects, and should be set at the respective IOU's PURPA avoided cost rate, as determined by the Commission through an administrative process.[25] As noted in the Decision, the use of PURPA avoided costs to compensate generation resources will not result in a cost shift to non-participating ratepayers.[26]

Community Solar Adder

The Community Solar Adder should also be consistent across all IOU and CCA CRE projects and would be paid for through CRE Funding.[27] The purpose of this adder would be to

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[24] *See* D.24-05-065 at 79.

[25] *See e.g.* Resolution E-5323 (Adoption of 2024 updated administratively set fixed avoided-cost rates for the ReMAT program pursuant to D.20-10-005); *see also* D.20-05-006, OP 1 and OP 2 (determining the calculation of energy and capacity prices under the standard offer contract program).

[26] D.24-05-065 at 124.

[27] As noted in section II.B above, "CRE Funding" is defined as the $33 million appropriated to the Commission by Assembly Bill 102 (2023) for community energy renewable program usage and storage-

encourage the development of projects in areas where the load is located and to develop true *community-based* renewable energy projects (i.e. projects are located "close" to where customers are located).[28] This value would be similar to the "above market generation costs" under the DAC-GT program, but unlike the DAC-GT above market generation costs (which vary by project), would be set at the same level across all CRE projects.

The Joint CCAs propose that the Commission convene a working group to further discuss the appropriate value of the Community Solar Adder. For example, one issue that should be investigated is whether it would appropriate to provide local resources in load pockets with additional value for the avoided costs of using the transmission system. It should also be investigated further if it is appropriate to derive the Community Solar Adder from other small-scale renewable energy feed-in-tariffs ("FITs") like the ReMAT. Another option is to consider historic costs for local capacity as an adder for resources that can count for RA. The question of how local FTM DERs can be valued has been an issue of much discussion in this instant proceeding and the Joint CCAs believe that a Commission-organized working group would provide the appropriate venue for developing an appropriate valuation methodology.

Grid Capacity Adder

The Grid Capacity Adder would be included for projects that are located in a capacity constrained area and would be paid for by the IOUs. The IOUs should make a proposal on how to develop the Grid Capacity Adder based on their experience under the Distribution Investment Deferral Framework ("DIDF") solicitation process.[29] In the past, the IOUs have recommended

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backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding.

[28] See a proposed definition for proximity between customers and projects in Section II.A.i. above.

[29] To date, the DIDF solicitations have largely been unsuccessful. It is currently being discussed in the Commission's High DER Rulemaking (R.21-06-017) if the DIDF solicitations should be terminated.

that resources would have to participate in designated solicitation processes such as the DIDF to gain access to additional locational benefits and value. For example, for a DAC-GT resource to receive locational value, it would have to participate (and be selected) in both the DAC-GT and the DIDF solicitations. This is a cumbersome and impractical process for any developer that has never been successful to date. To give projects in grid constrained areas more timely and direct access to additional locational benefits, the Joint CCAs recommend that the utilities propose a methodology to provide a "Grid Capacity Adder" under the CRE Program itself.

Community Goals Adder (or "CCA Adder")

The Community Goals Adder would be specific to the CCA CRE Program and would be paid for by the participating CCA. Under this proposal, a CCA can choose to adjust the PPA price to align with the CCAs' avoided procurement costs and/or to support specific goals and interests of the CCA and its community. For example, a CCA is likely to have avoided procurement costs that differ from their respective IOU and could therefore choose to modify the value to a developer beyond the IOU's PURPA avoided cost (which is the base payment under the CRE Program). Many CCAs also have specific goals and interests in their community (e.g. rehabilitation of brownfields, reduction of local air quality impacts due to fossil-fuel power stations, or development of local projects in disadvantaged communities ("DACs")) and may therefore be willing to provide additional value to the developer under the CRE Program. The Community Goals Adder would be different for each CCA, with each participating CCA proposing the value of the adder in their respective SOC documents.

Any discussions in the High DER Rulemaking should inform the Grid Capacity Adder proposal the IOUs make for the CRE Program.

The Joint CCAs provide a summary of the PPA elements, with example pricing, in Table 1 below.[30] The Joint CCAs recommend that a separate pricing structure is developed for solar and storage resources based on the service they provide, rather than a blended rate.[31] This provides more flexibility to developers and allows for co-located (rather than just hybrid) solar and storage resources as provided for in the Decision.[32]

Table 1: Example of Proposed PPA Structure

PPA Element	Solar ($/MWh)	Storage ($/kW-month)	Cost Recovered by
Base payment	$30	$15	Participating LSE
Community Solar Adder	$20	$2	CRE Funding
Grid Capacity Adder	$20	$2	IOU
Community Goals Adder	$20	$2	CCA
TOTAL	$90	$21	

Finally, the Joint CCAs recommend that the PPA pricing (and associated adders) could be adjusted based on industry responses to CRE solicitations, similar to the ReMAT program. For example, if few (or no) responses are received to a CRE solicitation, the Community Solar Adder could increase by a certain percentage to further encourage participation in the solicitation. After a successful CRE solicitation, the adders could be decreased for the next tranche of the CRE Program solicitation.

ii. Participant Revenue Share (or "Customer Incentive")

Per the Decision, all residential customers, as well as small commercial customers, are eligible to enroll as subscribers to the CRE Program. However, the Decision only adopts a minimum revenue share (or customer incentive) for low-income subscribers and declines to

[30] Note that pricing is approximated and does not necessarily reflect actual market costs.

[31] The Joint CCAs note that a blended rate could be calculated by the participating program administrators for the purposes of calculating the subscriber incentives as further described below in response to Question 2.

[32] D.24-05-065 at 169, OP 1(i). Co-located resources typically have separate prices for solar and storage resources while hybrid solar and storage resources use a blended rate.

specify a minimum revenue share for non-low-income (i.e. "general market" subscribers) as they will not receive a subsidy through external funding.[33]

The Joint CCAs support SCE's proposal that the program should provide a flat monetary credit based on a percentage of the contracted project compensation (i.e. the PPA price) for low-income subscribers. General market subscribers would not receive an incentive but would also not have to pay for the above-market generation costs incurred by the resources under the program. In other words, all subscribing customers remain on their otherwise applicable tariff ("OAT") when enrolling under the CRE Program. Low-income customers only will then receive an annual bill credit based on a percentage of the PPA price. The Joint CCAs discuss the level of incentives for low-income customers in more detail in response to Question 2 below.

2. *Decision (D.)24-05-065 states, "The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit." What should the revenue share for low-income subscribers be and how should it be calculated? Comments should consider that some external funding types may have certain conditions to ensure the funding benefits low-income customers.*

As noted above in response to Question 1, the Joint CCAs support SCE's proposal to provide low-income subscribers with an incentive based on 20% of the PPA price provided under the specific CRE project that the customer subscribes to. In a simple example, if a customer were to subscribe to a solar-only project that has a PPA price of $90/MWh, the customer incentive rate would be set at $18/MWh (i.e., the "CRE Incentive Rate"). The customer incentive credit would then be calculated during an annual "true-up" process by multiplying the customer's usage over the previous 12 months with the CRE Incentive Rate. Under this example, a customer with a 6 MWh annual usage would receive an annual bill credit of $108.

[33] *Id*. at 120

While this calculation is relatively straightforward for solar only projects, it is a bit more complex to calculate a 20% share for PPA prices that are composed of both an energy price ($/MWh) for the solar resource and a capacity price ($/kW-month) for the storage resource.[34] Under the example provided in response to Question 1 above, the solar resource would be paid $90/MWh and the storage system $21/kW-month. If one were to convert the storage system's capacity price into an energy price to create a blended $/MWh rate, and then take 20% of the blended PPA price, the customer would receive a CRE Incentive Rate of $52.6/MWh.[35] In this case, a customer with a 6 MWh annual usage would receive an annual bill credit of $315.60, a significant increase compared to the annual bill credit of $108 for a solar resource only. For comparison purposes, under MCE's DAC-GT program, low-income customers received an average of $450 in bill credits in 2023 (calculated as a 20% bill discount off the electric portion of their bill).[36]

Effectively, low-income customers subscribed to a solar-only CRE project would receive only about one third of the annual incentive that DAC-GT participants receive (under the assumptions of the above example). However, as CRE Funding is limited, this would allow for more customers to be subscribed under the program and to provide an incentive to a larger number of low-income customers. This would also help meet AB 2316's statutory objective to "promote robust participation by low-income customers."[37]

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[34] The Joint CCAs maintain that the developers should be paid two separate prices for their solar and storage resources to enable the participation of co-located resources.

[35] The blended PPA rate is calculated as follows: a 4-hour, 1MW battery would generate 1460 MWhs of energy annually and would get paid $252,000 per year, which comes to an $/MWh rate of $173/MWh. The blended PPA price would be $263/MWh ($90/MWh for the solar resource). 20% of the blended PPA rate amounts to a CRE Incentive Rate of $52.60.

[36] *See* MCE Advice Letter 79-E.

[37] Pub. Util. Code Section 769.3(b)(1)(3).

Low-income customers subscribed to a solar and storage CRE project would receive approximately the same annual incentive that DAC-GT participants receive. While this may generally be a desirable outcome, the Joint CCAs would like to note that CRE Funding will be expended very quickly on a limited number of customers due to the high customer incentive costs. The Joint CCAs elaborate on the challenges regarding limited CRE Funding in Section II.B above.

In summary, when implementing the CRE Program, the Commission must find a balance between providing reasonable incentives to low-income customers while also reaching as many customers as possible. The Joint CCAs believe that the proposed rate structure outlined above is a reasonable approximation of what the CRE Incentive Rate could look like. However, the Joint CCAs are also open to discussing further modifications to the methodology with stakeholders to strike the right balance between the level of low-income customer incentives and the number of program participants.

3. *D.24-05-065 states "With respect to bill credits, the Commission finds the [Southern California Edison (SCE)] proposal to use the simplified Shared Savings Model using balancing accounts to provide a flat monetary credit on subscriber bills is reasonable…The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit. A future ruling in this proceeding will allow for additional record development. The Commission also declines to specify a minimum revenue share for -non-low-income-subscribers as they will not receive a subsidy through external funding." Propose, in detail, how a low-income and non-low-income bill credit should be applied, including billing presentment.*

As noted above in response to Question 1, the Joint CCAs propose that non-low-income subscribers would not receive an incentive and would remain on their OAT. Low-income customers would receive an incentive calculated as 20% of the PPA price, as further detailed in response to Question 2. Additionally, while the Joint CCAs currently propose that non-low-

income subscribers would not receive incentives, to the extent the Commission determines that general market subscribers are required to receive a percentage of the revenue share under Public Utilities Code Section 769.3(c)(5), the Joint CCAs would support an incentive of up to 10% of the PPA price for non-low-income customers (calculated as described above in response to Question 2). However, as this incentive would not be provided through the currently available external funding, it is unclear how the costs for this incentive would be covered.[38]

The Joint CCAs further propose that for low-income customers, the incentive would be applied directly to the customers' generation portion of their electric bills after the annual true-up process. As the customer incentive would be covered by CRE Funding, both IOUs and CCAs would seek cost recovery for the bill credit from the IOU balancing account tracking the CRE Funding. The Joint CCAs propose that this process follows the same process as the DAC-GT program. Namely, a CCA participating in the CRE Program would submit an annual budget advice letter to the Commission and the IOUs would distribute funding to the CCAs in advance. The CRE Program budgets would then be trued-up on an annual basis.

B. Non-Ratepayer-Funded Adder

4. *What should be the developer incentive or adder per project and how should it be calculated? Potential funding sources include the Environmental Protection Agency's (EPA) Solar for All grant funding, General Funds allocated to the Commission, and others to be determined.*
    a. *Should the incentives for developers be based on dollars per watt, dollars per kilowatt-hour, a lump sum, or some other scheme? Explain why.*

As noted above in response to Question 1, the Joint CCAs propose that the developer be compensated based on the PPA price offered by the LSE in its SOC. Solar resources would be paid a $/MWh price for the energy produced by the system. Solar plus storage resources would

[38] *See* D.24-05-065 (noting that non-low-income subscribers will not receive a subsidy through external funding).

offer a distinct pricing structure for the solar and the storage resource (where solar would be paid a $/MWh price for the energy produced and storage would be paid a $/kW-month price for the capacity provided by the system). Basing developer compensation on a PPA price or storage rate is the standard mechanism for LSEs to procure FTM resources and the simplest and most efficient way to structure developer compensation under the CRE Program.

> b. *What process should the Commission use for determining the incentive or adder? Should the Commission set the incentive or adder price administratively or should it require the utilities to use a method such as a reverse auction that would introduce price discovery? If you recommend a price discovery method, specify the method you propose and the justification for using that method.*

As further discussed in response to Question 1 above, the Joint CCAs propose that the Commission establish a working group process to discuss the valuation of the Community Solar Adder. The Joint CCAs also provide proposals for how the Grid Capacity Adder and Community Goals Adder should be set in response to Question 1(a).

> c. *Should the incentive or adder be based on a minimum dollar amount per customer or a minimum percentage of project revenue share? Should the incentive or adder increase if more low income customers are signed up beyond the 51 percent per project minimum threshold?*

As noted above in response to Question 1, the Joint CCAs recommend that the developer be compensated under a standard PPA, not based on a minimum revenue share or dollar per customer amount. Developers should also not receive an increased adder or incentive based on the number of low-income customers subscribed in the CRE Program, especially as developers will not be involved in the recruitment of subscribing customers under the CCA proposal (as noted in Section II.A.ii, LSEs would be responsible for enrolling eligible customers, not developers).

d. What other non-monetary incentives or assistance could utilities or Community Choice Aggregators (CCAs) provide to community renewable energy program projects and developers?

See a detailed description of the "Grid Capacity Adder" (provided by the IOUs) and the "Community Goals Adder" (provided by CCAs) above in response to Question 1.

C. Federal Incentives

5. Some CCAs who administer the Disadvantaged Communities Green Tariff (DAC-GT) have successfully negotiated lower Power Purchase Agreement contract prices with selected developers if a project receives the federal Investment Tax Credit (ITC) Low-Income Community Bonus Credit. Similarly, the Solar on Multifamily Affordable Housing program also set a precedent for aligning incentives, such as the federal ITC, with incentives provided for the installation of solar. Should the new community renewable energy program follow a similar process for leveraging the federal incentives available in the Inflation Reduction Act including the Low-Income Community Bonus Credit and other new and available tax credits?

As the Joint CCAs have previously noted in this proceeding, it is important for renewable energy projects to take advantage of federal tax credits.[39] However, it is common practice for project developers to incorporate the Investment Tax Credit ("ITC") and similar benefits into PPA pricing. The Joint CCAs do not believe it is necessary to incorporate any requirement within the CRE program to encourage these incentives.

D. Disbursal of Non-Ratepayer Funds

6. D.24-05-065 states "Utilities would have the role of fiscal agents and apply monetary credits to the generation, i.e., benefiting, and customer, i.e., subscriber, accounts. The Commission finds that it is reasonable to direct Utilities to establish a balancing account to track the subscriber revenue shares and distribute the appropriate shares through the bill credit. Further, changes to the credits based on facility performance and credit distribution can be easily updated through an annual trueup process." How should the external funding be disbursed to the projects and participating customers of Utilities and CCAs?

[39] *See* Reply Brief of the Joint Community Choice Aggregators and City and County of San Francisco at 14.

As described in the Decision, the IOUs would create balancing accounts for CRE Funding which is expected to be the $33 million in general funds and a to-be-determined amount of the EPA's Solar for All Funding. Under the CCAs' proposal, the IOUs would also create another sub-account under the same balancing account to track and disburse the IOU-provided "Grid Capacity Adder".

Similar to the DAC-GT program, the Joint CCAs propose that both IOUs and CCAs would submit an annual budget advice letter forecasting the costs for the CRE Program and specifying which costs are recovered from which balancing sub-account (CRE Funding vs. Grid Capacity Adder). The IOUs would provide the CCAs with the forecasted funding for the CCA CRE Program in anticipation of expenses to be incurred. The CRE Program budgets would then be trued-up on an annual basis.

E. Treatment of Utility Implementation and Administrative Costs

7. *What funding source should be used to pay for start-up costs and program administration and what process should be used for cost recovery? This may include costs associated with billing system updates, the customer enrollment process buildout, ongoing subscription management and development of a new solar and storage contract (if needed).*

The Joint CCAs note that existing community solar programs, such as the DAC-GT program, cover administrative costs with ratepayer funds which cover program start-up costs such as billing system updates, the customer enrollment process etc. For more details, see the Joint CCAs' response to Question 22 below. These administrative costs were not accounted for in the Decision for the new CRE Program. However, such costs are necessary to implement a successful program. As noted above in Section II.B., the Joint CCAs are concerned that the currently allocated external CRE Funding can only support customer incentives, above-market generation costs, and administrative costs for a small program capacity. Therefore, the Joint

CCAs strongly recommend that other funding sources be identified to make this program more viable.

F. CCA Participation

8. *D.24-05-065 states "As CCAs are permitted to participate in the new community renewable energy program, the foundational tariffs will need to be revised to accommodate this participation. At this time, the record does not contain the specifics for CCA participation."*
    a. *What process should be employed to enable CCA participation in the community renewable energy program? This would include discussion of how CCAs must notify the Commission of their participation in accordance with Pub. Util. Code Section 769.3(b)(2)(B) and the process for CCAs to access external funds?*

Pursuant to Public Utilities Code Section 769.3(b)(2)(B), if the Commission establishes a new community renewable energy program, each CCA "shall notify whether it will participate in the program, within 180 days of the *establishment* [emphasis added] of the program."[40] As evidenced by the ALJ Ruling, there are still many remaining questions regarding the implementation of a CRE Program. Further, the Decision notes that the Commission intends to address CRE Program implementation issues through a subsequent implementation decision.[41] CCAs will not be able to properly determine whether to participate in the new program until most of the implementation questions and issues have been resolved. Therefore, the Joint CCAs recommend that the CRE Program be determined "established" for purposes of the 180 day deadline when the second decision is issued determining the details of the CRE Program.[42] Upon the issuance of the second decision, CCAs that are interested in offering the CRE Program would then have 180 days to submit their own CRE Program tariffs (i.e., the SOCs), as well as additional program implementation details, to the Commission via a Tier 2 Advice Letter. This

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[40] Pub. Util. Code § 769.3(b)(2)(B).

[41] D.24-05-065 at 123.

[42] *See id*. at 123, 147 (noting that a second proposed decision will be issued to finalize outstanding implementation issues associated with the new program).

process would both (1) notify the Commission of the CCA's intent to participate in the program and (2) provide the necessary tariff and implementation details for Commission consideration of the CCA's participation in the CRE Program. Upon approval of the Tier 2 AL, the CCA would make the CRE SOC publicly available and prepare for program launch. This process follows the example of the rollout of the DAC-GT programs offered by CCAs.

b. Which CCA tariffs should be eligible for the program?

The Joint CCAs propose the creation of new CCA SOCs as foundational tariffs for the CRE Program. See more details about the contract structure in Section II.A.i above. Furthermore, each CCA will share the specific details of their SOC (e.g. the details about the individual CCA Community Goals Adder) when submitting the necessary tariff documents to the Commission in the Tier 2 AL described in response to Question 8(a) above.

G. Enrollment

10. Should Utility-facilitated or CCA-facilitated auto-enrollment be the only enrollment pathway for low-income customers in DAC-GT and the new community renewable energy program? What other enrollment options are available? What are the benefits or drawbacks of either approach? Comments should consider potential administrative cost, alignment with other low-income programs like the California Alternate Rates for Energy (CARE) program, compatibility with Title 24, the customer enrollment experience, ease of customer understanding billing/crediting, and consumer protections.

The Joint CCAs understand that the Decision requires automatic enrollment for the CRE Program.[43] The Decision further specifies that low-income customers enrolled in the IOU or CCA Arrearage Management Program should be prioritized for automatic enrollment, followed by all other low-income customers who subscribe to the tariff.[44] The Joint CCAs propose that

[43] D.24-05-065 at 119.
[44] *Id*.

non-low-income customers would not need to be auto-enrolled and would, instead, voluntarily subscribe to the CRE Program.

The Decision follows the auto-enrollment approach utilized in D.20-07-008 and Resolution E-5124 for the modified DAC-GT program.[45] In Resolution E-5124, the Commission recognized that CCAs designing their own auto-enrollment criteria, instead of using specific statewide criteria, could prevent program implementation delays.[46] Pursuant to D.20-07-008[47] and Resolution E-5124,[48] CCA program administrators have created auto-enrollment criteria and also offered self-enrollment options for eligible customers that indicate interest in joining the DAC-GT program voluntarily. The Joint CCAs support the existing auto-enrollment process for the modified DAC-GT program and maintaining self-enrollment opportunities for customers otherwise eligible under a CCA's auto-enrollment criteria.

> *11. If you recommend auto-enrollment, describe the criteria that should be used for i) determining which customers would be auto-enrolled in the community renewable energy program and ii) ensuring that customers aren't enrolled in more than one program (i.e. community renewable energy program and DAC-GT). Additionally, explain which program (i.e. community renewable energy program and DAC-GT) would low-income customers be enrolled in first?*

The Joint CCAs note that there are different eligibility requirements under the CRE Program and the DAC-GT program. The DAC-GT program is available to low-income residents who reside in DACs and are eligible for either the CARE or FERA programs.[49] Low-income

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45 *Id*. at 133.

46 Resolution E-5124 at 19 (providing "that CCAs design their auto-enrollment criteria in such a way as to prevent issues and further program implementation delays from occurring, while still retaining alignment with D.20-07-008").

47 D.20-07-008 at 14, OP 2.

48 Resolution E-5124 at 19, 31.

49 *See* Resolution E-5212.

customers eligible for the CRE Program as defined by Assembly Bill 2316 is a much broader group.[50]

Acknowledging the discrepancy in the eligible customers between the two programs, the Joint CCAs believe that low-income customers and the customers who are at the highest risk of being disconnected should be enrolled in whichever program provides the highest benefit and/or the largest discount on their monthly bills that they may be eligible for. Based on the Joint CCAs' current understanding of the new CRE Program, the Joint CCAs believe the DAC-GT program would likely provide the higher benefit to low-income customers as the program guarantees that customers will receive 20% off their electric bills. As such, the Joint CCAs propose that DAC-GT eligible customers first be enrolled in the DAC-GT program with remaining customers automatically enrolled in the CRE Program (up to the program cap). However, the final determination for the customer incentive under the CRE Program has not yet been made. It will be important to consider party comments in response to Question 1 of the Ruling and the Commission's ultimate determination on this issue prior to making a final determination on which program customers should be enrolled in first.

IV. RESPONSES TO RULING QUESTIONS: MODIFIED DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM

> *12. Determining the prior year spending for multiple DAC-GT program administrators on is a challenging task which requires review of multiple annual budget advice letters. Explain whether you think it would be simpler to have one of the three investor-owned utilities submit an annual report on behalf of all DAC-GT administrators showing historical spending each year in the first quarter?*

It is unclear from the question whether an annual report submitted by the IOUs on behalf of all the DAC-GT program administrators would be in lieu of the annual budget advice letters

[50] *See* Pub. Util. Code Section 769.3(a)(3).

("ABALs"), or in addition to the ABALs. The Decision clarifies that the submission date of the ABALs is moved from February 1 to April 1 of each year,[51] however the instant question seems to suggest that an annual reporting process would be "simpler" than the submission of the ABALs. In general, the Joint CCAs do not object to an annual report containing public information providing details on the prior years' spending for the DAC-GT program. However, it is not practical for an annual report to be submitted by one of the IOUs that either (i) requires the coordination and transfer of confidential data to the IOUs for submission or (ii) prevents each program administrator's budget from being independently reviewed by the Commission as is the current process through the ABALs.

First, it would be burdensome to coordinate the transfer of confidential data to the IOUs for submission in an annual report replacing the ABALs. Second, in the original decision, each CCA's administrative and marketing costs must be approved by the Commission as those costs are capped.[52] This submission and approval process requires a Tier 2 AL submission from each program administrator.[53] Due to this, the Joint CCAs understand that each ABAL must be reviewed individually to assess the cost caps, and a joint submission by one IOU would be unnecessary and would cause confusion should one program administrator's costs need to be reevaluated by the Commission. Therefore, the Joint CCAs would object to an IOU reporting process that replaced the ABAL submissions.

Additionally, while the Joint CCAs would not have an objection to an annual report submitted by an IOU that contains public information to facilitate stakeholder review of relevant spending for the DAC-GT program, any annual report should be submitted in the second, or even

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[51] D.24-05-065 at 134.

[52] *See* Resolution E-4999 (establishing a 10 percent cost cap for program administration and 4 percent cost cap for marketing, education, and outreach).

[53] *See id*. at 68, OP 4.

third, quarter of the year to ensure the information being provided is accurate. Specifically, a budget report should not be posted until after the review and disposition of the initial program administrator ABALs. As noted in the Decision, the ABAL submission deadline was moved from February 1 to April 1 to allow for improved accuracy in tracking costs.[54] Requiring submission of an annual report in the first quarter of each year would negate this improvement and result in inaccurate spending data.

> *13. In D.04-12-048 of the Long-Term Procurement Planning Proceeding, the Commission required Utilities to hire an Independent Evaluator to monitor competitive solicitations that involve affiliate transactions, Utility-built or Utility turnkey bidders. Subsequently, D.06-05-039 required an Independent Evaluator to also monitor all Renewables Portfolio Standard program solicitations to separately evaluate and report on a Utility's entire solicitation, evaluation and selection process for this and all future solicitations. The Independent Evaluator serves as an independent check on final selections, by ensuring solicitations are conducted in an open, fair, and transparent process. Should the Independent Evaluator for each Utility be required to submit a report for all Utility DAC-GT procurements, whether or not a Request For Offer results in a selected bid?*

The Joint CCAs do not take a position on this question as the Independent Evaluator required by D.06-05-039 applies only to the IOUs.

V. RESPONSES TO RULING QUESTIONS: MODIFIED AND LEGACY GREEN TARIFF AND SHARED RENEWABLES

A. Incremental Renewable Procurement – All Parties Respond

D.24-05-065 adopts the Utilities' proposal to bundle any future solicitations for new resources to meet modified green tariff demand with the same procurement activities it will undertake to meet its long-term planning goals to ensure least cost best-fit procurement. The Decision requires Utilities to each submit a Tier 2 Advice Letter updating their existing Green Access Program tariffs according to the directives of the decision, including details on how their programs will result in incremental new renewable energy being purchased.

> *17. Describe how additional renewable procurement should be accomplished, citing key dependencies to an approved Integrated Resource Plan Decision and process.*

[54] D.24-05-065 at 134.

a. How would a participant be assured that these resources are from incremental renewable resources?

As noted in Resolution E-4999, the purpose of creating the DAC-GT program was to promote development of new renewable energy projects in DACs.[55] Pursuant to the DAC-GT program implementation Resolutions, DAC-GT program administrators must submit executed PPAs no later than 180 days following notification of selected bidders of solicitations. This process has demonstrated that the projects used to serve the DAC-GT program are new renewable energy projects. The modified DAC-GT program will continue to submit PPAs to the Commission through an Advice Letter process. The Joint CCAs believe these PPA submissions should provide sufficient detail that the proposed projects are new incremental projects. Additionally, any projects will be included in the program administrators' Integrated Resource Plans which are also reviewed by the Commission. The Joint CCAs believe any dependencies created between the Integrated Resource Planning process and the DAC-GT or new CRE Programs would be unnecessary and overly complicated.

VI. RESPONSES TO RULING QUESTIONS: ALL CALIFORNIA RENEWABLES PORTFOLIO PROGRAMS

22. For the legacy Green Tariff, modified Green Tariff, and Disadvantaged Communities Green Tariff programs, provide a breakdown of budget line items by category and program, using the same categories used in Exhibit CA-01 Appendix B. Are there other cost categories, such as a regulatory compliance line item, that should be included in the programs' reporting?

The Joint CCAs support a budget line item breakdown consisting of four main categories: (i) above market generation costs, (ii) bill discount, (iii) program administration, and (iv) ME&O as used in Exhibit CA-01 Appendix B. While the Joint CCAs believe these main categories sufficiently make up the programs' reporting, some program administrators provide additional

[55] Resolution E-4999 at 23.

detail on cost breakdowns within these categories. For example, "program administration" often includes the following sub-categories: (i) program management, (ii) information technology ("IT"), (iii) billing operations, (iv) regulatory compliance, and (v) procurement. Additionally, ME&O costs would include (i) labor costs, and (ii) outreach and material costs. If budget line items are broken down further from the main categories listed above and included in Exhibit CA-01, the Joint CCAs request that, at a minimum, these subcategories also be included.

VII. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

July 10, 2024

Respectfully Submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

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July 10, 2024

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I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC" or "Commission") *Administrative Law Judge's Ruling Directing Response to Questions Regarding Implementation of Decision 24-05-065* dated June 5, 2024 ("ALJ Ruling" or "Ruling"), Ava Community Energy, Clean Power Alliance of Southern California, the City and County of San Francisco, acting by and through its Public Utilities Commission, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, San Diego Community Power, San Jacinto Power, and San José Clean Energy (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Opening Comments.

The Joint CCAs appreciate the Commission's aim to expeditiously resolve implementation issues associated with the modified Disadvantaged Communities Green Tariff ("DAC-GT") and the new Community Renewable Energy ("CRE") programs as adopted by

Decision ("D.") 24-05-065, *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program* ("the Decision"). The Joint CCAs support the Commission's goal of furthering the development of local, front-of-the-meter ("FTM") distributed energy resources ("DERs") – community solar and storage resources in particular – and look forward to collaborating with the Commission on developing the details that would allow interested Community Choice Aggregators ("CCAs") to offer a CCA-led CRE Program. As noted in the Ruling and the Decision, the record does not contain specifics for CCA participation, and there are open questions associated with which tariffs and processes should be in place to enable interested CCAs to participate in the CRE Program.[1] In these comments, the Joint CCAs outline the cornerstones of a proposed CRE Program that can incorporate both investor-owned utility ("IOU") and CCA tariffs. While the Joint CCAs propose to largely align the CRE Program between IOU and CCA administrators, there are a few instances where program rules may differ (as further outlined below).

The Joint CCAs' comments are structured in three sections. Section II provides a summary of the Joint CCAs' CRE Program proposal and highlights concerns regarding the financial viability of the CRE Program with current funding allocations. Section III answers specific questions in the ALJ Ruling regarding the CRE Program, providing additional details regarding the Joint CCAs' CRE Program proposal as it relates specifically to developer compensation and the "subscriber revenue share" (referred to hereafter as "customer incentives"). Finally, Sections IV through VI respond to select Ruling questions regarding the modification of the DAC-GT program.

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[1] *See* D.24-05-065 at 148 ("As CCAs are permitted to participate in the new community renewable energy program, the foundational tariffs will need to be revised to accommodate this participation. At this time, the record does not contain the specifics for CCA participation"); *see also* Ruling at 7 (requesting comment on which process should be employed to enable CCA participation).

II. SUMMARY OF CCA CRE PROGRAM PROPOSAL

A. The New CRE Program Must Equally Incorporate IOU and CCA Tariffs

The Joint CCAs support greater development of distributed FTM resources, and appreciate the opportunity to provide feedback on the new CRE Program to ensure that interested CCAs will be able to participate. The Decision specifies that the new CRE Program shall be based on one of the existing IOU tariffs that are compliant with the federal Public Utility Regulatory Policies Act ("PURPA"), such as the Renewable Market Adjusting Tariff ("ReMAT") and Standard-Offer-Contract ("SOC") tariffs.[2] However, as these are IOU-specific tariffs, the Commission also notes in the Decision that "the foundational tariffs will need to be revised to accommodate" CCA participation.[3] The Joint CCAs propose that both IOUs and CCAs use SOCs as foundational tariffs for the CRE Program. Specifically, the Joint CCAs propose to offer a SOC tariff that incorporates the IOUs' PURPA wholesale tariffs but which is governed by CCA tariff rules and principles. As noted above, the Joint CCAs recommend that program rules and requirements should largely be aligned between IOUs and CCAs offering the CRE Program, as is customary under the existing DAC-GT programs. This would ensure consistency between the various CRE Programs and would minimize confusion among customers and developers. As such, the Joint CCA proposal illustrated below would be consistent across both IOU and CCA program administrators with limited exceptions.

The Joint CCAs provide the following proposal as the basic underlying structure of the CRE Program, detailing the program's contract structure and project requirements. Further details regarding developer compensation and customer incentives are provided in Section III in response to the ALJ Ruling questions.

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[2] D.24-05-065 at 168, Ordering Paragraph ("OP") 1(a).

[3] *Id*. at 148.

i. Proposed CRE Contract Structure and Project Requirements

Similar to the IOUs, the Joint CCAs propose that interested CCAs would offer SOCs under the CRE Program in which a developer signs a power purchase agreement ("PPA") directly with the load serving entity ("LSE") (i.e., in this case, the CCA) for a 20-year delivery term. The 20-year delivery term is recommended to enable subscribing customers to meet Title 24 requirements by enrolling under a CRE project.

The Joint CCAs believe the CRE Program should be based on SOCs because this contract structure allows the developers insight into PPA prices, which in turn helps them assess the feasibility of project development. One of the hurdles the Joint CCAs have encountered under the DAC-GT and Community Solar Green Tariff ("CSGT") programs has been that developers are uncertain about the cost cap for PPAs because that information is confidential. The Joint CCAs understand that developers may choose not to participate in DAC-GT or CSGT solicitations due to the perception that the prices for their projects may be too high. A set PPA price under a SOC construct would remove this uncertainty. This construct would also reduce PPA negotiations and bid pricing reviews, leading to program administration efficiencies and price consistency for customers throughout the state.

As detailed further in response to Question 1 in Section III below, the Joint CCAs are proposing that the CRE Program PPA price be based on several components, including a PPA base payment and additional price adders. Consistent with the Decision, the Joint CCAs propose that the PPA base payment would be based on the PURPA avoided costs for both IOU and CCA projects,[4] with additional "adders" provided to appropriately value the local DERs. While the

[4] *Id*. at 125 ("The adopted community renewable energy program will compensate generating resources based on the PURPA avoided costs of the facility…[T]he Commission will use its own method to determine the avoided cost of the generating resource, with PURPA guidance.")

Joint CCAs are amenable to adopting the PURPA avoided costs as the base PPA price under the CRE Program, it must be highlighted that CCAs do not fall under PURPA compliance and CCA avoided generation costs are likely to differ from the IOUs' avoided costs.

The CRE Program resources would consist of solar, or solar plus storage, projects.[5] The Joint CCAs propose certain locational requirements to support *community-based* solar or solar plus storage projects, and to ensure that projects are located in areas where the load (or customer) is located. In the case of a CCA offering the CRE Program, one could argue that the resource is implicitly "local" if it is located in a CCA's (more geographically limited) service area and will only serve CCA customers. However, the same is not necessarily true for IOU projects due to the vast size of the IOUs' service territories.[6] For these reasons, the Joint CCAs propose that CRE projects must be located within 50 miles of subscribing customers for both IOU and CCA-led CRE Programs (or vice versa, subscribing customers must be located within 50 miles of the CRE resource). The Joint CCAs are open to considering other locational requirements as proposed by stakeholders in response to this Ruling.

Additionally, CRE resources must be integrated into the California Independent System Operator ("CAISO") market. It is essential that resources under the program can receive resource adequacy ("RA") credit. However, RA credits are only possible if the resource can receive deliverability status, which has been an observed barrier for distributed resources because the deliverability allocation process is an ill fit for projects of this type. If it is cost prohibitive or otherwise not feasible for the resource to get deliverability, the Commission should work with

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[5] *Id*. at 169, OP 1(i) ("Storage – The community renewable energy program tariff shall allow for co-located solar and storage.")

[6] Pacific Gas & Electric ("PG&E"), for example, could technically locate a resource in Fresno and serve customers in Humboldt County if the locational requirement under the CRE Program would be the LSE's service area, thereby defeating the purpose of a *community* renewable energy program.

the California Energy Commission ("CEC") to allow a resource to get RA credit as a load modifier via the LSE's year-ahead RA forecast by virtue of reducing the LSE's RA obligation.[7] Such coordination would preferably occur prior to contracting, to provide LSEs certainty that they would receive RA credit for resources under the program and to minimize redundant RA costs for customers.

The Joint CCAs propose a minimum project size of 500 kW and a maximum project size of 5 MW under both the IOU and CCA CRE Programs.[8] As further detailed below, the current allocated funding amount will effectively limit the CRE Program to around 50 MW of capacity, and the limitation of the project size can ensure that more distributed resources are being built under the program to benefit more localized communities. Furthermore, it should be a primary goal of the program to site resources in areas where load is located, thereby reducing the likelihood of land availability for large resources. For those reasons, the Joint CCAs recommend a smaller maximum system size than the one proposed in the Decision.

Contrary to Southern California Edison's ("SCE") proposal, the Joint CCAs do not recommend that projects *must* be located in capacity constrained areas.[9] The Joint CCAs propose

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[7] The Net Value Billing Tariff ("NVBT") proposal previously included a proposal for resources as load modifiers on the CEC year-ahead RA forecast which the Joint CCAs objected to. However, those concerns related to the fact that only LSEs file year-ahead RA forecasts with the CEC, and under the NVBT proposal, the LSEs would not have held the contract with the resource developer. Under the CCA CRE Program, the LSE would be the counterparty on the resource and would, therefore, have more insight into the resource. The Joint CCA acknowledge that there would be many implementation details associated with this proposal, including coordination with the CEC and, therefore, offer this as a suggestion for conversation moving forward.

[8] *See* D.24-05-065 at 156 (The Joint CCAs are proposing a maximum project size under the 20 MW limit set by the Decision); *See also* Cal. Code Regs, tit. 24, pt. 1 §10-115(a)(7) ("The community shared solar electric generation system and/or community shared battery storage system shall not be served by an individual source larger than 20 MW.").

[9] *See* D.24-05-065 at 79 ("Other parameters of SCE's proposal include a maximum facility size of three megawatts, a capacity constrained site location requirement, a combine solar and storage requirement (allowing for Renewable Energy Credits), and a requirement that storage dispatch rights be provided to the contracting utility.").

to offer a PPA adder to projects located in capacity constrained areas but recommend against *requiring* project siting in those areas. This requirement would limit project siting too much and would require IOU analyses which have been unavailable in the past.[10]

Finally, in accordance with Assembly Bill 2316 and the Decision, developers must demonstrate that all projects shall comply with the prevailing wage requirement,[11] and must further demonstrate to the CEC that the proposal complies with Section 10-115 of the California Building Code.[12]

ii. CRE Customer Eligibility

Each LSE would enroll eligible customers in their respective CRE Programs.[13] Per the Decision, all residential customers (i.e. low-income and non-low-income), as well as small commercial customers, will be eligible to enroll as subscribers to the CRE Program.[14] In accordance with Assembly Bill 2316 and the Decision, the Joint CCAs propose that at least 51% of each project's capacity under the CRE program must be subscribed by low-income customers.[15] Low-income customers are defined as individuals or households who qualify for the California Alternate Rates for Energy ("CARE") program, Family Electric Rate Assistance ("FERA") program, CalFresh, Supplemental Nutrition Assistance Program ("SNAP"), or the Low-income Heating Energy Assistance Program ("LIHEAP"), or reside in an underserved

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[10] *See generally* Rulemaking 21-06-017 Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future ("High DER Rulemaking") including discussions about locating distributed resources in areas of grid constraint.

[11] D.24-05-065 at 169, OP 1(h).

[12] *Id*. at 168-169, OP 1(f).

[13] Customers will be subscribed to a portion of a CRE project based on their previous 12-months load. If only partial or no previous load is available, customer load can be estimated. The same process is used for DAC-GT customer enrollment.

[14] Technically, OP 1(d) of D.24-05-065 states that "*All [emphasis added]* customers will be eligible to enroll as subscribers to the tariff" (i.e. residential and non-residential customers alike). See D.24-05-065 at 168. However, the Decision's text at 119 implies that only residential customers, and small commercial customers, are the intended participants under the program.

[15] D.24-05-065 at 169, OP 1(g).

community which includes low-income communities as defined in Health & Safety Code Section 39713, communities within the 25% most disadvantaged communities according to the CalEnviroScreen, and communities located on tribal lands.[16]

The remaining 49% of a project's capacity is not limited to a certain customer type but, as noted in the Decision, it is recommended that this capacity would focus on enrolling non-low-income customers who rent or lease.[17]

Per the Decision, low-income customers would be auto-enrolled under the CRE Program. The Joint CCAs further discuss auto-enrollment provisions in response to Question 9 in Section III below.

B. Any CRE Program Implemented by the Commission Must Take Into Account Current Funding Limitations

Some parties have raised the concern that the current funding expected to be available for the CRE Program is too limited to create an impactful program.[18] The Joint CCAs agree. The Commission has noted in the Decision that it will set aside certain funding for the CRE Program, namely $33 million appropriated to the Commission by Assembly Bill 102 (2023) for community energy renewable program usage and storage-backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding (collectively referred to herein as "CRE Funding").[19] California was awarded $249,800,000 in

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[16] *See* Pub. Util. Code Section 769.3(a)(3).

[17] D.24-05-065 at 118.

[18] *See* Comments of Cypress Creek Renewables, LLC on the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 12; Clean Coalition Comments on Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 3; Comments of The Solar Energy Industries Association on Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 14.

[19] D.24-05-064 at 118 (citing AB 102, Budget Act of 2023, Section 244 appropriated $33 million to the Commission with additional requirements.)

Solar for All funding but it is not clear how much of that funding will be set aside for the CRE Program.[20] If an estimated $100 million is set aside from the EPA's Solar for All funding, in total, the CRE Program would have a statewide budget of $133 million.

While the Decision does not establish a program capacity cap, the program's capacity is implicitly limited by the funding available for the program. As is discussed further below in Section III in response to Questions 1- 4, the CCAs are proposing that the CRE Funding would pay for two core components of the program: (1) the customer incentives (i.e. revenue share) paid to participating low-income customers and (2) the "Community Solar Adder", an adder contributing to the overall PPA price paid to the developer. The Joint CCAs would also expect CRE Funding to cover administrative costs of the CRE Program. This is in alignment with the DAC-GT program, where ratepayer funds are used to cover (1) the bill discount paid to participating low-income customers, (2) the "above-market generation costs" of the solar (and storage) resource, *and* (3) administrative and marketing, education and outreach ("ME&O") costs of the program.

Even if CRE Funding were to only cover customer incentives and the Community Solar Adder, the current funding allocation of an estimated $133 million would only allow for approximately 50 MW of statewide program capacity based on the estimated pricing assumptions that the Joint CCAs use in Table 1 below.[21] The Joint CCAs would like to highlight

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[20] *See* Solar for All Selected Applicants, available at: https://www.epa.gov/greenhouse-gas-reduction-fund/solar-all; *See also* D.24-05-065 at 118 fn 327 (stating that "some portion" of the funds would support the community renewable energy program).

[21] In the example outlined below, the CRE Funding would cover $20/MWh for the Community Solar Adder and $2/kW-month for the Community Storage Adder for a blended rate of $36.44/MWh. The CRE Funding would also cover $52.52/MWh for the CRE solar + storage Incentive Rate for 50% of customers (only low-income) leading to total costs of $62.7/MWh. $133 million in funding can cover around 106,000MWh annually (over a 20-year contract period), and if one assumes an even split of MWhs between the solar and the storage resource, the CRE Funding could cover around 20MW in solar and 36MW in storage resource for a combined program capacity of 56MW.

that such a limited program cap (and estimated funding amount) may be insufficient to incentivize the administrative effort necessary to develop a new community renewable energy program in California. As noted above, the Joint CCAs support the development of local FTM DERs but also want to caution that adequate funding must be available to make the program successful (if not feasible). Commissioner Houck also acknowledged the current funding limitations for the CRE Program and the risks it poses to the success of the program in her dissent to the recent Decision.[22] The Joint CCAs strongly recommend that the Commission take these funding limitations into consideration when further developing the CRE program and consider potential avenues for additional funding that may be available for this program.

III. RESPONSES TO RULING QUESTIONS: NEW COMMUNITY RENEWABLE ENERGY PROGRAM

A. Revenue Share and Bill Credits

1. *The new community renewable energy program is designed to deliver value through two streams of funding: (i) the stable but moderately adjusting compensation from wholesale tariffs and (ii) the external, nonratepayer, funding or "adder" that is managed through investor-owned utility (Utility) balancing accounts. How should these streams of funding be applied to provide both developer compensation and subscriber savings or revenue share (i.e., percentage split of total revenue from a project between the developer or generator account and benefiting or subscriber accounts)?*

The Joint CCAs make the following proposal regarding the structure of the developer compensation and the subscriber's "incentive"[23] for the CRE Program (including IOU and CCA tariffs). These proposals are based on SCE's proposal provided in SCE's Opening Comments to the *Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value*

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[22] *See* Concurrence and Dissent of Commissioner Darcie L. Houck as to the Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program.

[23] As described above, the Joint CCAs call the subscriber's "revenue share" an "incentive" as it more appropriately describes the form of payment the customer receives. Following SCE's proposal, the customer does not receive a share of the projects revenue (which would be CAISO revenues), but instead the customer incentive is calculated as a percentage of the PPA price.

Benefit Tariff Proposal, dated November 6, 2024 , as well as the requirements of the Decision with slight proposed modifications.

i. Developer Compensation

The Joint CCAs agree with SCE's proposal that developers be paid based on the project's PPA price.[24] Importantly, the PPA would braid several different value streams together to ensure that the developers are encouraged to develop local, community-based solar, or solar plus storage, projects. The Joint CCAs propose that the PPA price offered under the CRE Program be comprised of three core elements: (i) a base payment, (ii) a Community Solar Adder, and (iii) a Grid Capacity Adder. Additionally, for the *CCA* CRE Programs specifically, an individual CCA has the discretion to add a fourth element, a "Community Goals Adder." The following describes each of the proposed PPA elements in more detail.

Base Payment

The base payment should be consistent across IOU and CCA CRE projects, and should be set at the respective IOU's PURPA avoided cost rate, as determined by the Commission through an administrative process.[25] As noted in the Decision, the use of PURPA avoided costs to compensate generation resources will not result in a cost shift to non-participating ratepayers.[26]

Community Solar Adder

The Community Solar Adder should also be consistent across all IOU and CCA CRE projects and would be paid for through CRE Funding.[27] The purpose of this adder would be to

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[24] *See* D.24-05-065 at 79.

[25] *See e.g.* Resolution E-5323 (Adoption of 2024 updated administratively set fixed avoided-cost rates for the ReMAT program pursuant to D.20-10-005); *see also* D.20-05-006, OP 1 and OP 2 (determining the calculation of energy and capacity prices under the standard offer contract program).

[26] D.24-05-065 at 124.

[27] As noted in section II.B above, "CRE Funding" is defined as the $33 million appropriated to the Commission by Assembly Bill 102 (2023) for community energy renewable program usage and storage-

encourage the development of projects in areas where the load is located and to develop true *community-based* renewable energy projects (i.e. projects are located "close" to where customers are located).[28] This value would be similar to the "above market generation costs" under the DAC-GT program, but unlike the DAC-GT above market generation costs (which vary by project), would be set at the same level across all CRE projects.

The Joint CCAs propose that the Commission convene a working group to further discuss the appropriate value of the Community Solar Adder. For example, one issue that should be investigated is whether it would appropriate to provide local resources in load pockets with additional value for the avoided costs of using the transmission system. It should also be investigated further if it is appropriate to derive the Community Solar Adder from other small-scale renewable energy feed-in-tariffs ("FITs") like the ReMAT. Another option is to consider historic costs for local capacity as an adder for resources that can count for RA. The question of how local FTM DERs can be valued has been an issue of much discussion in this instant proceeding and the Joint CCAs believe that a Commission-organized working group would provide the appropriate venue for developing an appropriate valuation methodology.

Grid Capacity Adder

The Grid Capacity Adder would be included for projects that are located in a capacity constrained area and would be paid for by the IOUs. The IOUs should make a proposal on how to develop the Grid Capacity Adder based on their experience under the Distribution Investment Deferral Framework ("DIDF") solicitation process.[29] In the past, the IOUs have recommended

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backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding.

[28] See a proposed definition for proximity between customers and projects in Section II.A.i. above.

[29] To date, the DIDF solicitations have largely been unsuccessful. It is currently being discussed in the Commission's High DER Rulemaking (R.21-06-017) if the DIDF solicitations should be terminated.

that resources would have to participate in designated solicitation processes such as the DIDF to gain access to additional locational benefits and value. For example, for a DAC-GT resource to receive locational value, it would have to participate (and be selected) in both the DAC-GT and the DIDF solicitations. This is a cumbersome and impractical process for any developer that has never been successful to date. To give projects in grid constrained areas more timely and direct access to additional locational benefits, the Joint CCAs recommend that the utilities propose a methodology to provide a "Grid Capacity Adder" under the CRE Program itself.

Community Goals Adder (or "CCA Adder")

The Community Goals Adder would be specific to the CCA CRE Program and would be paid for by the participating CCA. Under this proposal, a CCA can choose to adjust the PPA price to align with the CCAs' avoided procurement costs and/or to support specific goals and interests of the CCA and its community. For example, a CCA is likely to have avoided procurement costs that differ from their respective IOU and could therefore choose to modify the value to a developer beyond the IOU's PURPA avoided cost (which is the base payment under the CRE Program). Many CCAs also have specific goals and interests in their community (e.g. rehabilitation of brownfields, reduction of local air quality impacts due to fossil-fuel power stations, or development of local projects in disadvantaged communities ("DACs")) and may therefore be willing to provide additional value to the developer under the CRE Program. The Community Goals Adder would be different for each CCA, with each participating CCA proposing the value of the adder in their respective SOC documents.

Any discussions in the High DER Rulemaking should inform the Grid Capacity Adder proposal the IOUs make for the CRE Program.

The Joint CCAs provide a summary of the PPA elements, with example pricing, in Table 1 below.[30] The Joint CCAs recommend that a separate pricing structure is developed for solar and storage resources based on the service they provide, rather than a blended rate.[31] This provides more flexibility to developers and allows for co-located (rather than just hybrid) solar and storage resources as provided for in the Decision.[32]

Table 1: Example of Proposed PPA Structure

PPA Element	Solar ($/MWh)	Storage ($/kW-month)	Cost Recovered by
Base payment	$30	$15	Participating LSE
Community Solar Adder	$20	$2	CRE Funding
Grid Capacity Adder	$20	$2	IOU
Community Goals Adder	$20	$2	CCA
TOTAL	$90	$21	

Finally, the Joint CCAs recommend that the PPA pricing (and associated adders) could be adjusted based on industry responses to CRE solicitations, similar to the ReMAT program. For example, if few (or no) responses are received to a CRE solicitation, the Community Solar Adder could increase by a certain percentage to further encourage participation in the solicitation. After a successful CRE solicitation, the adders could be decreased for the next tranche of the CRE Program solicitation.

ii. Participant Revenue Share (or "Customer Incentive")

Per the Decision, all residential customers, as well as small commercial customers, are eligible to enroll as subscribers to the CRE Program. However, the Decision only adopts a minimum revenue share (or customer incentive) for low-income subscribers and declines to

[30] Note that pricing is approximated and does not necessarily reflect actual market costs.

[31] The Joint CCAs note that a blended rate could be calculated by the participating program administrators for the purposes of calculating the subscriber incentives as further described below in response to Question 2.

[32] D.24-05-065 at 169, OP 1(i). Co-located resources typically have separate prices for solar and storage resources while hybrid solar and storage resources use a blended rate.

specify a minimum revenue share for non-low-income (i.e. "general market" subscribers) as they will not receive a subsidy through external funding.[33]

The Joint CCAs support SCE's proposal that the program should provide a flat monetary credit based on a percentage of the contracted project compensation (i.e. the PPA price) for low-income subscribers. General market subscribers would not receive an incentive but would also not have to pay for the above-market generation costs incurred by the resources under the program. In other words, all subscribing customers remain on their otherwise applicable tariff ("OAT") when enrolling under the CRE Program. Low-income customers only will then receive an annual bill credit based on a percentage of the PPA price. The Joint CCAs discuss the level of incentives for low-income customers in more detail in response to Question 2 below.

2. *Decision (D.)24-05-065 states, "The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit." What should the revenue share for low-income subscribers be and how should it be calculated? Comments should consider that some external funding types may have certain conditions to ensure the funding benefits low-income customers.*

As noted above in response to Question 1, the Joint CCAs support SCE's proposal to provide low-income subscribers with an incentive based on 20% of the PPA price provided under the specific CRE project that the customer subscribes to. In a simple example, if a customer were to subscribe to a solar-only project that has a PPA price of $90/MWh, the customer incentive rate would be set at $18/MWh (i.e., the "CRE Incentive Rate"). The customer incentive credit would then be calculated during an annual "true-up" process by multiplying the customer's usage over the previous 12 months with the CRE Incentive Rate. Under this example, a customer with a 6 MWh annual usage would receive an annual bill credit of $108.

[33] *Id*. at 120

While this calculation is relatively straightforward for solar only projects, it is a bit more complex to calculate a 20% share for PPA prices that are composed of both an energy price ($/MWh) for the solar resource and a capacity price ($/kW-month) for the storage resource.[34] Under the example provided in response to Question 1 above, the solar resource would be paid $90/MWh and the storage system $21/kW-month. If one were to convert the storage system's capacity price into an energy price to create a blended $/MWh rate, and then take 20% of the blended PPA price, the customer would receive a CRE Incentive Rate of $52.6/MWh.[35] In this case, a customer with a 6 MWh annual usage would receive an annual bill credit of $315.60, a significant increase compared to the annual bill credit of $108 for a solar resource only. For comparison purposes, under MCE's DAC-GT program, low-income customers received an average of $450 in bill credits in 2023 (calculated as a 20% bill discount off the electric portion of their bill).[36]

Effectively, low-income customers subscribed to a solar-only CRE project would receive only about one third of the annual incentive that DAC-GT participants receive (under the assumptions of the above example). However, as CRE Funding is limited, this would allow for more customers to be subscribed under the program and to provide an incentive to a larger number of low-income customers. This would also help meet AB 2316's statutory objective to "promote robust participation by low-income customers."[37]

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[34] The Joint CCAs maintain that the developers should be paid two separate prices for their solar and storage resources to enable the participation of co-located resources.

[35] The blended PPA rate is calculated as follows: a 4-hour, 1MW battery would generate 1460 MWhs of energy annually and would get paid $252,000 per year, which comes to an $/MWh rate of $173/MWh. The blended PPA price would be $263/MWh ($90/MWh for the solar resource). 20% of the blended PPA rate amounts to a CRE Incentive Rate of $52.60.

[36] *See* MCE Advice Letter 79-E.

[37] Pub. Util. Code Section 769.3(b)(1)(3).

Low-income customers subscribed to a solar and storage CRE project would receive approximately the same annual incentive that DAC-GT participants receive. While this may generally be a desirable outcome, the Joint CCAs would like to note that CRE Funding will be expended very quickly on a limited number of customers due to the high customer incentive costs. The Joint CCAs elaborate on the challenges regarding limited CRE Funding in Section II.B above.

In summary, when implementing the CRE Program, the Commission must find a balance between providing reasonable incentives to low-income customers while also reaching as many customers as possible. The Joint CCAs believe that the proposed rate structure outlined above is a reasonable approximation of what the CRE Incentive Rate could look like. However, the Joint CCAs are also open to discussing further modifications to the methodology with stakeholders to strike the right balance between the level of low-income customer incentives and the number of program participants.

3. *D.24-05-065 states "With respect to bill credits, the Commission finds the [Southern California Edison (SCE)] proposal to use the simplified Shared Savings Model using balancing accounts to provide a flat monetary credit on subscriber bills is reasonable…The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit. A future ruling in this proceeding will allow for additional record development. The Commission also declines to specify a minimum revenue share for -non-low-income-subscribers as they will not receive a subsidy through external funding." Propose, in detail, how a low-income and non-low-income bill credit should be applied, including billing presentment.*

As noted above in response to Question 1, the Joint CCAs propose that non-low-income subscribers would not receive an incentive and would remain on their OAT. Low-income customers would receive an incentive calculated as 20% of the PPA price, as further detailed in response to Question 2. Additionally, while the Joint CCAs currently propose that non-low-

income subscribers would not receive incentives, to the extent the Commission determines that general market subscribers are required to receive a percentage of the revenue share under Public Utilities Code Section 769.3(c)(5), the Joint CCAs would support an incentive of up to 10% of the PPA price for non-low-income customers (calculated as described above in response to Question 2). However, as this incentive would not be provided through the currently available external funding, it is unclear how the costs for this incentive would be covered.[38]

The Joint CCAs further propose that for low-income customers, the incentive would be applied directly to the customers' generation portion of their electric bills after the annual true-up process. As the customer incentive would be covered by CRE Funding, both IOUs and CCAs would seek cost recovery for the bill credit from the IOU balancing account tracking the CRE Funding. The Joint CCAs propose that this process follows the same process as the DAC-GT program. Namely, a CCA participating in the CRE Program would submit an annual budget advice letter to the Commission and the IOUs would distribute funding to the CCAs in advance. The CRE Program budgets would then be trued-up on an annual basis.

B. Non-Ratepayer-Funded Adder

4. *What should be the developer incentive or adder per project and how should it be calculated? Potential funding sources include the Environmental Protection Agency's (EPA) Solar for All grant funding, General Funds allocated to the Commission, and others to be determined.*
    a. *Should the incentives for developers be based on dollars per watt, dollars per kilowatt-hour, a lump sum, or some other scheme? Explain why.*

As noted above in response to Question 1, the Joint CCAs propose that the developer be compensated based on the PPA price offered by the LSE in its SOC. Solar resources would be paid a $/MWh price for the energy produced by the system. Solar plus storage resources would

[38] *See* D.24-05-065 (noting that non-low-income subscribers will not receive a subsidy through external funding).

offer a distinct pricing structure for the solar and the storage resource (where solar would be paid a $/MWh price for the energy produced and storage would be paid a $/kW-month price for the capacity provided by the system). Basing developer compensation on a PPA price or storage rate is the standard mechanism for LSEs to procure FTM resources and the simplest and most efficient way to structure developer compensation under the CRE Program.

> b. *What process should the Commission use for determining the incentive or adder? Should the Commission set the incentive or adder price administratively or should it require the utilities to use a method such as a reverse auction that would introduce price discovery? If you recommend a price discovery method, specify the method you propose and the justification for using that method.*

As further discussed in response to Question 1 above, the Joint CCAs propose that the Commission establish a working group process to discuss the valuation of the Community Solar Adder. The Joint CCAs also provide proposals for how the Grid Capacity Adder and Community Goals Adder should be set in response to Question 1(a).

> c. *Should the incentive or adder be based on a minimum dollar amount per customer or a minimum percentage of project revenue share? Should the incentive or adder increase if more low income customers are signed up beyond the 51 percent per project minimum threshold?*

As noted above in response to Question 1, the Joint CCAs recommend that the developer be compensated under a standard PPA, not based on a minimum revenue share or dollar per customer amount. Developers should also not receive an increased adder or incentive based on the number of low-income customers subscribed in the CRE Program, especially as developers will not be involved in the recruitment of subscribing customers under the CCA proposal (as noted in Section II.A.ii, LSEs would be responsible for enrolling eligible customers, not developers).

d. What other non-monetary incentives or assistance could utilities or Community Choice Aggregators (CCAs) provide to community renewable energy program projects and developers?

See a detailed description of the "Grid Capacity Adder" (provided by the IOUs) and the "Community Goals Adder" (provided by CCAs) above in response to Question 1.

C. Federal Incentives

5. Some CCAs who administer the Disadvantaged Communities Green Tariff (DAC-GT) have successfully negotiated lower Power Purchase Agreement contract prices with selected developers if a project receives the federal Investment Tax Credit (ITC) Low-Income Community Bonus Credit. Similarly, the Solar on Multifamily Affordable Housing program also set a precedent for aligning incentives, such as the federal ITC, with incentives provided for the installation of solar. Should the new community renewable energy program follow a similar process for leveraging the federal incentives available in the Inflation Reduction Act including the Low-Income Community Bonus Credit and other new and available tax credits?

As the Joint CCAs have previously noted in this proceeding, it is important for renewable energy projects to take advantage of federal tax credits.[39] However, it is common practice for project developers to incorporate the Investment Tax Credit ("ITC") and similar benefits into PPA pricing. The Joint CCAs do not believe it is necessary to incorporate any requirement within the CRE program to encourage these incentives.

D. Disbursal of Non-Ratepayer Funds

6. D.24-05-065 states "Utilities would have the role of fiscal agents and apply monetary credits to the generation, i.e., benefiting, and customer, i.e., subscriber, accounts. The Commission finds that it is reasonable to direct Utilities to establish a balancing account to track the subscriber revenue shares and distribute the appropriate shares through the bill credit. Further, changes to the credits based on facility performance and credit distribution can be easily updated through an annual trueup process." How should the external funding be disbursed to the projects and participating customers of Utilities and CCAs?

[39] *See* Reply Brief of the Joint Community Choice Aggregators and City and County of San Francisco at 14.

As described in the Decision, the IOUs would create balancing accounts for CRE Funding which is expected to be the $33 million in general funds and a to-be-determined amount of the EPA's Solar for All Funding. Under the CCAs' proposal, the IOUs would also create another sub-account under the same balancing account to track and disburse the IOU-provided "Grid Capacity Adder".

Similar to the DAC-GT program, the Joint CCAs propose that both IOUs and CCAs would submit an annual budget advice letter forecasting the costs for the CRE Program and specifying which costs are recovered from which balancing sub-account (CRE Funding vs. Grid Capacity Adder). The IOUs would provide the CCAs with the forecasted funding for the CCA CRE Program in anticipation of expenses to be incurred. The CRE Program budgets would then be trued-up on an annual basis.

E. Treatment of Utility Implementation and Administrative Costs

7. *What funding source should be used to pay for start-up costs and program administration and what process should be used for cost recovery? This may include costs associated with billing system updates, the customer enrollment process buildout, ongoing subscription management and development of a new solar and storage contract (if needed).*

The Joint CCAs note that existing community solar programs, such as the DAC-GT program, cover administrative costs with ratepayer funds which cover program start-up costs such as billing system updates, the customer enrollment process etc. For more details, see the Joint CCAs' response to Question 22 below. These administrative costs were not accounted for in the Decision for the new CRE Program. However, such costs are necessary to implement a successful program. As noted above in Section II.B., the Joint CCAs are concerned that the currently allocated external CRE Funding can only support customer incentives, above-market generation costs, and administrative costs for a small program capacity. Therefore, the Joint

CCAs strongly recommend that other funding sources be identified to make this program more viable.

F. CCA Participation

8. *D.24-05-065 states "As CCAs are permitted to participate in the new community renewable energy program, the foundational tariffs will need to be revised to accommodate this participation. At this time, the record does not contain the specifics for CCA participation."*
    a. *What process should be employed to enable CCA participation in the community renewable energy program? This would include discussion of how CCAs must notify the Commission of their participation in accordance with Pub. Util. Code Section 769.3(b)(2)(B) and the process for CCAs to access external funds?*

Pursuant to Public Utilities Code Section 769.3(b)(2)(B), if the Commission establishes a new community renewable energy program, each CCA "shall notify whether it will participate in the program, within 180 days of the *establishment* [emphasis added] of the program."[40] As evidenced by the ALJ Ruling, there are still many remaining questions regarding the implementation of a CRE Program. Further, the Decision notes that the Commission intends to address CRE Program implementation issues through a subsequent implementation decision.[41] CCAs will not be able to properly determine whether to participate in the new program until most of the implementation questions and issues have been resolved. Therefore, the Joint CCAs recommend that the CRE Program be determined "established" for purposes of the 180 day deadline when the second decision is issued determining the details of the CRE Program.[42] Upon the issuance of the second decision, CCAs that are interested in offering the CRE Program would then have 180 days to submit their own CRE Program tariffs (i.e., the SOCs), as well as additional program implementation details, to the Commission via a Tier 2 Advice Letter. This

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[40] Pub. Util. Code § 769.3(b)(2)(B).

[41] D.24-05-065 at 123.

[42] *See id*. at 123, 147 (noting that a second proposed decision will be issued to finalize outstanding implementation issues associated with the new program).

process would both (1) notify the Commission of the CCA's intent to participate in the program and (2) provide the necessary tariff and implementation details for Commission consideration of the CCA's participation in the CRE Program. Upon approval of the Tier 2 AL, the CCA would make the CRE SOC publicly available and prepare for program launch. This process follows the example of the rollout of the DAC-GT programs offered by CCAs.

b. Which CCA tariffs should be eligible for the program?

The Joint CCAs propose the creation of new CCA SOCs as foundational tariffs for the CRE Program. See more details about the contract structure in Section II.A.i above. Furthermore, each CCA will share the specific details of their SOC (e.g. the details about the individual CCA Community Goals Adder) when submitting the necessary tariff documents to the Commission in the Tier 2 AL described in response to Question 8(a) above.

G. Enrollment

10. Should Utility-facilitated or CCA-facilitated auto-enrollment be the only enrollment pathway for low-income customers in DAC-GT and the new community renewable energy program? What other enrollment options are available? What are the benefits or drawbacks of either approach? Comments should consider potential administrative cost, alignment with other low-income programs like the California Alternate Rates for Energy (CARE) program, compatibility with Title 24, the customer enrollment experience, ease of customer understanding billing/crediting, and consumer protections.

The Joint CCAs understand that the Decision requires automatic enrollment for the CRE Program.[43] The Decision further specifies that low-income customers enrolled in the IOU or CCA Arrearage Management Program should be prioritized for automatic enrollment, followed by all other low-income customers who subscribe to the tariff.[44] The Joint CCAs propose that

[43] D.24-05-065 at 119.
[44] *Id*.

non-low-income customers would not need to be auto-enrolled and would, instead, voluntarily subscribe to the CRE Program.

The Decision follows the auto-enrollment approach utilized in D.20-07-008 and Resolution E-5124 for the modified DAC-GT program.[45] In Resolution E-5124, the Commission recognized that CCAs designing their own auto-enrollment criteria, instead of using specific statewide criteria, could prevent program implementation delays.[46] Pursuant to D.20-07-008[47] and Resolution E-5124,[48] CCA program administrators have created auto-enrollment criteria and also offered self-enrollment options for eligible customers that indicate interest in joining the DAC-GT program voluntarily. The Joint CCAs support the existing auto-enrollment process for the modified DAC-GT program and maintaining self-enrollment opportunities for customers otherwise eligible under a CCA's auto-enrollment criteria.

> *11. If you recommend auto-enrollment, describe the criteria that should be used for i) determining which customers would be auto-enrolled in the community renewable energy program and ii) ensuring that customers aren't enrolled in more than one program (i.e. community renewable energy program and DAC-GT). Additionally, explain which program (i.e. community renewable energy program and DAC-GT) would low-income customers be enrolled in first?*

The Joint CCAs note that there are different eligibility requirements under the CRE Program and the DAC-GT program. The DAC-GT program is available to low-income residents who reside in DACs and are eligible for either the CARE or FERA programs.[49] Low-income

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45 *Id*. at 133.

46 Resolution E-5124 at 19 (providing "that CCAs design their auto-enrollment criteria in such a way as to prevent issues and further program implementation delays from occurring, while still retaining alignment with D.20-07-008").

47 D.20-07-008 at 14, OP 2.

48 Resolution E-5124 at 19, 31.

49 *See* Resolution E-5212.

customers eligible for the CRE Program as defined by Assembly Bill 2316 is a much broader group.[50]

Acknowledging the discrepancy in the eligible customers between the two programs, the Joint CCAs believe that low-income customers and the customers who are at the highest risk of being disconnected should be enrolled in whichever program provides the highest benefit and/or the largest discount on their monthly bills that they may be eligible for. Based on the Joint CCAs' current understanding of the new CRE Program, the Joint CCAs believe the DAC-GT program would likely provide the higher benefit to low-income customers as the program guarantees that customers will receive 20% off their electric bills. As such, the Joint CCAs propose that DAC-GT eligible customers first be enrolled in the DAC-GT program with remaining customers automatically enrolled in the CRE Program (up to the program cap). However, the final determination for the customer incentive under the CRE Program has not yet been made. It will be important to consider party comments in response to Question 1 of the Ruling and the Commission's ultimate determination on this issue prior to making a final determination on which program customers should be enrolled in first.

IV. RESPONSES TO RULING QUESTIONS: MODIFIED DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM

> *12. Determining the prior year spending for multiple DAC-GT program administrators on is a challenging task which requires review of multiple annual budget advice letters. Explain whether you think it would be simpler to have one of the three investor-owned utilities submit an annual report on behalf of all DAC-GT administrators showing historical spending each year in the first quarter?*

It is unclear from the question whether an annual report submitted by the IOUs on behalf of all the DAC-GT program administrators would be in lieu of the annual budget advice letters

[50] *See* Pub. Util. Code Section 769.3(a)(3).

("ABALs"), or in addition to the ABALs. The Decision clarifies that the submission date of the ABALs is moved from February 1 to April 1 of each year,[51] however the instant question seems to suggest that an annual reporting process would be "simpler" than the submission of the ABALs. In general, the Joint CCAs do not object to an annual report containing public information providing details on the prior years' spending for the DAC-GT program. However, it is not practical for an annual report to be submitted by one of the IOUs that either (i) requires the coordination and transfer of confidential data to the IOUs for submission or (ii) prevents each program administrator's budget from being independently reviewed by the Commission as is the current process through the ABALs.

First, it would be burdensome to coordinate the transfer of confidential data to the IOUs for submission in an annual report replacing the ABALs. Second, in the original decision, each CCA's administrative and marketing costs must be approved by the Commission as those costs are capped.[52] This submission and approval process requires a Tier 2 AL submission from each program administrator.[53] Due to this, the Joint CCAs understand that each ABAL must be reviewed individually to assess the cost caps, and a joint submission by one IOU would be unnecessary and would cause confusion should one program administrator's costs need to be reevaluated by the Commission. Therefore, the Joint CCAs would object to an IOU reporting process that replaced the ABAL submissions.

Additionally, while the Joint CCAs would not have an objection to an annual report submitted by an IOU that contains public information to facilitate stakeholder review of relevant spending for the DAC-GT program, any annual report should be submitted in the second, or even

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[51] D.24-05-065 at 134.

[52] *See* Resolution E-4999 (establishing a 10 percent cost cap for program administration and 4 percent cost cap for marketing, education, and outreach).

[53] *See id*. at 68, OP 4.

third, quarter of the year to ensure the information being provided is accurate. Specifically, a budget report should not be posted until after the review and disposition of the initial program administrator ABALs. As noted in the Decision, the ABAL submission deadline was moved from February 1 to April 1 to allow for improved accuracy in tracking costs.[54] Requiring submission of an annual report in the first quarter of each year would negate this improvement and result in inaccurate spending data.

> *13. In D.04-12-048 of the Long-Term Procurement Planning Proceeding, the Commission required Utilities to hire an Independent Evaluator to monitor competitive solicitations that involve affiliate transactions, Utility-built or Utility turnkey bidders. Subsequently, D.06-05-039 required an Independent Evaluator to also monitor all Renewables Portfolio Standard program solicitations to separately evaluate and report on a Utility's entire solicitation, evaluation and selection process for this and all future solicitations. The Independent Evaluator serves as an independent check on final selections, by ensuring solicitations are conducted in an open, fair, and transparent process. Should the Independent Evaluator for each Utility be required to submit a report for all Utility DAC-GT procurements, whether or not a Request For Offer results in a selected bid?*

The Joint CCAs do not take a position on this question as the Independent Evaluator required by D.06-05-039 applies only to the IOUs.

V. RESPONSES TO RULING QUESTIONS: MODIFIED AND LEGACY GREEN TARIFF AND SHARED RENEWABLES

A. Incremental Renewable Procurement – All Parties Respond

D.24-05-065 adopts the Utilities' proposal to bundle any future solicitations for new resources to meet modified green tariff demand with the same procurement activities it will undertake to meet its long-term planning goals to ensure least cost best-fit procurement. The Decision requires Utilities to each submit a Tier 2 Advice Letter updating their existing Green Access Program tariffs according to the directives of the decision, including details on how their programs will result in incremental new renewable energy being purchased.

> *17. Describe how additional renewable procurement should be accomplished, citing key dependencies to an approved Integrated Resource Plan Decision and process.*

[54] D.24-05-065 at 134.

a. How would a participant be assured that these resources are from incremental renewable resources?

As noted in Resolution E-4999, the purpose of creating the DAC-GT program was to promote development of new renewable energy projects in DACs.[55] Pursuant to the DAC-GT program implementation Resolutions, DAC-GT program administrators must submit executed PPAs no later than 180 days following notification of selected bidders of solicitations. This process has demonstrated that the projects used to serve the DAC-GT program are new renewable energy projects. The modified DAC-GT program will continue to submit PPAs to the Commission through an Advice Letter process. The Joint CCAs believe these PPA submissions should provide sufficient detail that the proposed projects are new incremental projects. Additionally, any projects will be included in the program administrators' Integrated Resource Plans which are also reviewed by the Commission. The Joint CCAs believe any dependencies created between the Integrated Resource Planning process and the DAC-GT or new CRE Programs would be unnecessary and overly complicated.

VI. RESPONSES TO RULING QUESTIONS: ALL CALIFORNIA RENEWABLES PORTFOLIO PROGRAMS

22. For the legacy Green Tariff, modified Green Tariff, and Disadvantaged Communities Green Tariff programs, provide a breakdown of budget line items by category and program, using the same categories used in Exhibit CA-01 Appendix B. Are there other cost categories, such as a regulatory compliance line item, that should be included in the programs' reporting?

The Joint CCAs support a budget line item breakdown consisting of four main categories: (i) above market generation costs, (ii) bill discount, (iii) program administration, and (iv) ME&O as used in Exhibit CA-01 Appendix B. While the Joint CCAs believe these main categories sufficiently make up the programs' reporting, some program administrators provide additional

[55] Resolution E-4999 at 23.

detail on cost breakdowns within these categories. For example, "program administration" often includes the following sub-categories: (i) program management, (ii) information technology ("IT"), (iii) billing operations, (iv) regulatory compliance, and (v) procurement. Additionally, ME&O costs would include (i) labor costs, and (ii) outreach and material costs. If budget line items are broken down further from the main categories listed above and included in Exhibit CA-01, the Joint CCAs request that, at a minimum, these subcategories also be included.

VII. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

July 10, 2024

Respectfully Submitted,

/s/ Brittany Iles

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July 17, 2024

VIA ELECTRONIC MAIL: edtariffunit@cpuc.ca.gov

Public Utilities Commission of the State of California
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Advice Letter 16-E **Apple Valley Choice Energy**	**Advice Letter 50-E** **Ava Community Energy**	**Advice Letter 42-E** **Central Coast Community Energy**
Advice Letter 10-E **Clean Energy Alliance**	**Advice Letter 30-E** **Clean Power Alliance of Southern California**	**Advice Letter 31-E** **CleanPowerSF**
Advice Letter 11-E **Desert Community Energy**	**Advice Letter 7-E** **Energy For Palmdale's Independent Choice**	**Advice Letter 30-E** **Lancaster Energy**
Advice Letter 80-E **Marin Clean Energy**	**Advice Letter 10-E** **Orange County Power Authority**	**Advice Letter 36-E** **Peninsula Clean Energy**
Advice Letter 25-E **Pico Rivera Innovative Municipal Energy**	**Advice Letter 20-E** **Pioneer Community Energy**	**Advice Letter 11-E** **Pomona Choice Energy**
Advice Letter 14-E **Rancho Mirage Energy Authority**	**Advice Letter 22-E** **Redwood Coast Energy Authority**	**Advice Letter 22-E** **San Diego Community Power**
Advice Letter 23-E **San Jacinto Power**	**Advice Letter 36-E** **San José Clean Energy**	**Advice Letter 7-E** **Santa Barbara Clean Energy**
Advice Letter 33-E **Silicon Valley Clean Energy**	**Advice Letter 24-E** **Sonoma Clean Power**	**Advice Letter 19-E** **Valley Clean Energy**

RE: Joint CCAs' New CCA Registration Requirements Tier 2 Advice Letter Pursuant to Decision (D.) 24-04-009

The California Community Choice Association (CalCCA) submits this Tier 2 Advice Letter (Advice Letter) on behalf of Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy,

Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy (collectively, the Joint CCAs).[1] This Advice Letter is submitted pursuant to Ordering Paragraph (OP) 5 of D.24-04-009[2] (the Decision). The Joint CCAs request the California Public Utilities Commission's (Commission) approval of this Advice Letter documenting new community choice aggregator (CCA) registration requirements.

I. TIER DESIGNATION

The Joint CCAs hereby submit this Advice Letter with a Tier 2 designation.

II. EFFECTIVE DATE

This Tier 2 Advice Letter will become effective upon disposition of this Advice Letter.

III. BACKGROUND

In D.05-12-041[3] and Resolution E-4907[4], the Commission requires new CCAs to submit an Implementation Plan. The Implementation Plan provides information regarding rate setting, organizational structure, operations, funding, and third-party power suppliers, as set forth in Public Utilities Code section 366.2. Within the provider of last resort (POLR) proceeding Rulemaking (R.) 21-03-011, CalCCA proposed the Commission enhance the implementation planning process with four requirements that would apply to newly forming CCAs: (1) submission of a feasibility study, if available, and pro forma financial statement with the Implementation Plan; (2) establishment of annual assumptions to be included in the pro forma financial statement; (3) establishment of milestones for critical implementation action and review progress; and (4) submission of an updated pro forma financial statement six months prior to launch. These requirements would apply to *newly forming* CCAs only, not existing CCAs expanding their service territories.

OP 5 of D.24-04-009 directs the CCAs to file a joint Tier 2 advice letter within 90 days of the Decision's effective date to further develop the additional registration requirements proposed by CalCCA. The Decision states, "Specifically, the advice letter filing should include an explanation of the type of annual assumptions that might be included in the pro forma financial statement, as well as example milestones for critical CCA implementation."[5]

As the Commission has previously acknowledged, Assembly Bill 117 (Migden, 2001) does not provide the Commission authority to approve or reject a CCA's implementation plan or to decertify

---

1 The Joint CCAs have provided CalCCA with authority to submit this Advice Letter on their behalf.

2 D.24-04-009, *Decision Implementing Senate Bill 520 Regarding Standards for Provider of Last Resort*, R.21-03-011 (Apr. 18, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M529/K986/529986322.PDF.

3 D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters*, R.03-10-003 (Dec. 16, 2005): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/52127.PDF,

4 Resolution E-4907, *Registration Process for Community Choice Aggregators* (Feb. 9, 2018): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K016/210016662.PDF.

5 D.24-04-009 at 86.

a CCA. Rather its role is to ensure that CCA Implementation Plans are consistent with utility tariffs and Commission rules designed to safeguard customers.[6] In recognition of the Commission's need to anticipate potential POLR needs, even among newly forming CCAs, the Joint CCAs propose the following example processes for newly registering CCAs to demonstrate the enactment of the necessary components outlined in California Public Utilities Code section 366.2.

IV. PROPOSAL

A. Annual Assumptions

Annual assumptions new CCAs use in their pro-forma financial statements should provide sufficient information to demonstrate forecasted expenses and revenues.[7] This should include, at minimum, how much energy the CCA forecasts it will use to determine energy and Renewables Portfolio Standard (RPS) costs, how much peak demand it will serve to determine resource adequacy (RA) costs, operations costs including facilities and personnel, and how it will charge its customers to obtain revenues to cover those costs, as follows:

- Annual forecast of financial projections using then-current reasonable proxy for energy cost projections and the Energy Resource Recovery Account Market Price Benchmarks for RA and RPS cost projections;
    - RPS cost assumptions should include, at minimum, the minimum RPS requirement in place at the time of the submittal of the pro forma financial statement.
    - RA cost assumptions should include, at minimum, the RA market price benchmark and RA need net of the Cost Allocation Mechanism allocation.
- Annual forecast of working capital needs including, at minimum, staffing needs and facility costs; and
- Annual forecast of cashflows, operating reserves, and lines of credit.

B. Milestones

While an Implementation Plan includes essential components, it is the responsibility of a CCA's governing board to determine how objectives are achieved. The suggested milestones do not influence the Commission's certification of a new CCA's Implementation Plan. Per California Public Utilities Code section 366.2, certifications must occur within 90 days, and any additional information requested is solely to assess the need for a cost recovery mechanism. Furthermore, the Commission must specify the earliest possible implementation date for the CCA program. These milestones do not grant additional authority to deny certification of an Implementation Plan, nor require resubmission or additional information from CCAs with an already Commission-approved Implementation Plan.

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[6] D.05-12-041 at 4.

[7] These forecasts should be based on the best information publicly available at the time and are subject to change as newer information becomes available.

Newly forming CCAs should incorporate the following best practice milestones to successfully implement a new CCA:

- Develop Implementation Plans
- Create a proposed schedule for key actions, including:
  - Adopt and implement staffing plan;
  - Secure financing;
  - Verify initial load projections;
  - Update pro forma financial statements;
  - Develop procurement plan for energy, RA, and RPS products;
  - Adopt rate design; and
  - Complete regulatory registrations needed for California Energy Commission, California Independent System Operator (CAISO), and Commission compliance.
- Complete the applicable CAISO requirements checklist or contract with a CAISO-certified Scheduling Coordinator.[8]
- Prepare and design customer enrollment notices.
- Create a process for notifying customers of their enrollment, deliver important updates about their enrollment, and collect enrollment data.
- Develop and maintain a detailed organization chart showing all roles required for responsible and sound operation of the CCA.

V. PROTEST

Anyone wishing to protest this Advice Letter may do so only by electronical mail. Protests must be received no later than 20 days after the date of this Advice Letter. Protests must be submitted to the Commission's Energy Division at:

E-mail: EDTariffUnitA@cpuc.ca.gov

In addition, protests and all other correspondence regarding this Advice Letter should also be sent by electronic mail, on the same date it is electronically delivered to the Commission, to the attention of:

California Community Choice Association
Attn: Evelyn Kahl
General Counsel and Director of Policy
regulatory@cal-cca.org

---

[8] Master Checklist for Certification: https://www.caiso.com/documents/masterchecklistforcertification-registrationrequirements.xlsx.

California Community Choice Association
Attn: Eric Little
Director of Regulatory Affairs
eric@cal-cca.org

California Community Choice Association
Attn: Lauren Carr
Senior Market Policy Analyst
lauren@cal-cca.org

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and a statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

VI. NOTICE

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter is being sent by electronic mail to each party of record in the official service list for R.21-03-011. For changes to this service list, please contact the Commission's Process Office at (415) 703-2021, or by electronic mail at Process_Office@cpuc.ca.gov.

VII. CORRESPONDENCE

All questions concerning this Advice Letter should be directed to Evelyn Kahl at (510) 980-9459, or by electronic mail at: regulatory@cal-cca.org.

VIII. CONCLUSION

The Joint CCAs respectfully request that the Commission approve the new CCA registration requirements within this Advice Letter.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl
General Counsel and Director of Policy

cc via email:
Service List: R.21-03-011

ADVICE LETTER SUMMARY
TO
JOINT CCAS' NEW CCA REGISTRATION REQUIREMENTS TIER 2
ADVICE LETTER PURSUANT TO DECISION D.24-04-009

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: California Community Choice Association

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Evelyn Kahl
Phone #: (510) 980-9459
E-mail: regulatory@cal-cca.org
E-mail Disposition Notice to: regulatory@cal-cca.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)
July 17, 2024

Advice Letter (AL) #: See Attached

Tier Designation: 2

Subject of AL: Joint CCAs New Community Choice Aggregator Registration Requirements Tier 2 Advice Letter Pursuant to Decision (D.) 24-04-009

Keywords (choose from CPUC listing):

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-04-009

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: Upon disposition

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Evelyn Kahl
Title: General Counsel and Director of Policy
Utility/Entity Name: California Community Choice Association

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: regulatory@cal-cca.org

Contact Name: Lauren Carr
Title: Senior Market Policy Analyst
Utility/Entity Name: California Community Choice Association

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: lauren@cal-cca.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

ADVICE LETTER SUMMARY ATTACHMENT
ADVICE LETTER NUMBERS

Advice Letter 16-E **Apple Valley Choice Energy**	**Advice Letter 50-E** **Ava Community Energy**	**Advice Letter 42-E** **Central Coast Community Energy**
Advice Letter 10-E **Clean Energy Alliance**	**Advice Letter 30-E** **Clean Power Alliance of Southern California**	**Advice Letter 31-E** **CleanPowerSF**
Advice Letter 11-E **Desert Community Energy**	**Advice Letter 7-E** **Energy For Palmdale's Independent Choice**	**Advice Letter 30-E** **Lancaster Energy**
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STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
07/19/24
02:58 PM
R2005003

July 19, 2024

Agenda ID #22771
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 20-05-003:

This is the proposed decision of Administrative Law Judge Julie A. Fitch. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 22, 2024 Business Meeting. To confirm when the item will be heard, please *see* the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF ALJ FITCH** **(Mailed 7/19/2024)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

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DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

Summary

This decision makes an initial need determination under the provisions of Assembly Bill 1373 (Stats. 2023, Ch.367), where the California Public Utilities Commission (Commission) may request that the Department of Water Resources (DWR) procure electricity from diverse long lead-time (LLT) resources on behalf of customers of all load-serving entities (LSEs) under the Commission's integrated resource planning (IRP) purview. This initial need determination totals up to 10.6 gigawatts (GW) of nameplate capacity of the following emerging technologies: up to 7.6 GW of offshore wind (OSW), up to 1 GW of enhanced geothermal systems (EGS), up to 1 GW of multi-day long-duration energy storage (LDES), and up to 1 GW of LDES with a discharge period of at least 12 hours.[1] A subsequent informal request may be sent to DWR within six months of the adoption of this decision asking that they initiate procurement activities.

The amounts selected are maximum amounts; once a procurement request is made, DWR will conduct solicitations and evaluate the quality of bids received, including costs and ratepayer risk provisions, and may procure anywhere between zero and the upper limits included in this decision. This flexibility will facilitate cost containment and minimize ratepayer risks.

The specific resources were selected because they are technologies that present opportunities to help California achieve our greenhouse gas (GHG) emissions reduction goals for 2045 and beyond, they represent emerging technologies that need to achieve economies of scale to bring costs down, and

[1] All capacity values in this decision are in nameplate capacity, which differs from prior procurement orders, which typically used net qualifying capacity.

they are also not currently being procured by individual LSEs in significant enough amounts to achieve cost reductions. The timing of the need determination herein is also after 2031, thus minimizing potential interference with LSE near-term procurement activities related to LLT resources. Centralized procurement of these resources may also make it easier, in the long term, for LSEs to procure more of these types of resources that may to be vital to achieving our long-term environmental goals.

At the same time, this decision recognizes that electricity rates are rising, creating hardships for ratepayers. Though the DWR centralized procurement mechanism should help bring emerging technologies to scale, the cost of these investments will ultimately impact electricity bills. Accordingly, all possible efforts should be made to contain costs, reduce ratepayer risk, and seek other sources of funding to reduce development costs and share in the long-term costs and benefits.

While we are cognizant that LLT resources targeted by this decision may have higher costs than the prevalent commercialized resources being procured by LSEs today, we also know that these LLT resources are frequently selected as part of our least-cost planning analysis for achieving California's long-term clean energy goals. Failure to make progress towards procurement of these LLT resources in the short term may ultimately lead to even higher ratepayer costs in the long term, if these resources are needed in the future with a shorter development timeline.

While selection of resources for centralized procurement here is intended to create opportunities for these resources to contributing to meeting our clean energy goals for 2045 and beyond, it is important to note that our determination is only that these resources could contribute to a pathway to meeting those goals,

not that these resources represent the only pathway to meeting those goals. We make a considerable need determination here to promote economies of scale that are necessary in order to create an opportunity for these emerging technologies to compete with more mature technologies to become part of our clean energy future, particularly given that economies of scale may be necessary for these resources to successfully compete with more mature technologies.

The total procurement may result in less than the 10.6 GW of total need determination being contracted for, approved by the Commission, and built. We will continue to monitor the procurement process for these resources and adjust other procurement requirements for LSEs accordingly.

LSEs will not be permitted to opt out of their share of centralized procurement authorized herein. The costs and benefits of any DWR centralized procurement approved will be allocated to all LSEs under the Commission's IRP purview. Additionally, publicly-owned utilities may opt in to allow their customers to share in the benefits of these valuable clean energy technologies.

For Commission LSEs, for EGS and OSW resources, because they are energy resources, the allocation will be on the basis of forecast annual energy load. For LDES resources, because they are capacity resources, allocation will be first to utility service area based on forecast 12-month peak load, and then further allocated to individual LSEs using the same methodology currently used for the Cost Allocation Mechanism.

This decision also requests that, for this LLT procurement, DWR convene a procurement group that includes representatives from LSEs. In addition, the decision sets a tentative schedule of solicitations, asking DWR to conduct two rounds of solicitations for LDES and EGS, beginning in 2026, and three rounds of solicitations for OSW beginning in 2027.

The Commission and staff will work closely with DWR as partners in the design and conduct of the solicitations. Results will be brought back to the Commission for reasonableness review and approval of proposed costs. Procedurally, Commission review will occur using a mechanism where DWR will submit a formal memo to this proceeding or its successor, and the Administrative Law Judge will then open a separate phase. This separate phase will address issues related to DWR's recommendations, reasonableness review of any proposed contracts, and the cost recovery for Commission-approved contracts. Finally, the Commission will reevaluate the need determination for additional LLT resources in every IRP cycle when considering a Preferred System Plan portfolio. In the next IRP cycle, the Commission will specifically evaluate LSE progress toward LLT procurement requirements in D.21-06-035, and consider whether an additional need determination for conventional geothermal resources for CPE procurement is necessary.

This proceeding remains open.

1. Background

Assembly Bill (AB) 1373 (Stats. 2023, Ch.367) was passed and signed by the Governor in 2023. AB 1373 authorizes the Commission to request that the Department of Water Resources (DWR) conduct centralized procurement of certain eligible long lead-time (LLT) resources, on behalf of customers of all load-serving entities (LSEs) under the Commission's integrated resource planning (IRP) purview.

By September 1, 2024, the Commission is required to make an initial need determination for procurement using a centralized procurement mechanism. If a need is found, within six months the Commission may then make a request to DWR to exercise the centralized procurement mechanism. In the event that DWR

performs centralized procurement on behalf of customers of LSEs under the Commission's purview and it is subsequently approved by the Commission, the Commission must then allocate the costs and benefits of any electric resource procurement conducted by DWR.

To make a need determination for the exercise of centralized procurement by DWR, AB 1373, codified as Public Utilities Code[2] Section 454.52(a)(4), directs that the Commission "determine if there is a need for the procurement of eligible energy resources based on a review of the integrated resource plans submitted by load-serving entities in compliance with the requirements of this section and Section 454.53 and the progress towards meeting the portfolio of resources identified pursuant to subdivision (a) of Section 454.51."[3][4]

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[2] Hereafter in this decision, all references to code sections are to the Public Utilities Code, unless otherwise noted.

[3] Section 454.53 states, among other things:

> It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035, 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040, 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045, and 100 percent of electricity procured to serve all state agencies by December 31, 2035.

[4] Section 454.51(a) states that the Commission shall:

> Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner. The portfolio shall be used by the commission to establish integrated resource planning-based procurement requirements that rely on zero-carbon-emitting resources to the maximum extent reasonable and be designed to achieve the state policy specified in Section 454.53 and any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation.

On April 26, 2024, the assigned Administrative Law Judge's (ALJ) ruling (ALJ Ruling) was issued seeking comments on the need and process for centralized procurement of LLTs by DWR in accordance with AB 1373. The ruling discussed resource eligibility, need determination, relationship to LSE procurement, allocation of costs and benefits, and the procurement process and timeline. The ruling also presented the results of a Commission staff and consultant analysis of the cost-effectiveness of offshore wind (OSW), in particular, as well as a qualitative assessment of the other potential eligible resources.

Comments were due by May 24, 2024, and were timely filed by the following parties: American Clean Power – California (ACP-CA); Advanced Energy United (AEU); Alliance for Retail Energy Markets (AReM) and the Regents of the University of California (UC Regents), jointly; Bay Area Municipal Transmission Group (BAMx); BHE Renewables, LLC (BHE); Bioenergy Association of California (BAC); Brightline Defense Project (Brightline); California Independent System Operator (CAISO); California Community Choice Association (CalCCA); California Community Power (CC Power); Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Calpine Corporation (Calpine); California Wind Energy Association (CalWEA); Center for Energy Efficiency and Renewable Technologies (CEERT); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Energy Storage Alliance (CESA); Coalition of California Utility Employees (CUE) and California Unions for Reliable Energy (CURE), jointly; Defenders of Wildlife (DOW); Environmental Defense Fund (EDF); Equinor Wind US LLC (Equinor); Fervo Energy Company (Fervo); Form Energy, Inc. (Form); Golden State Wind LLC (Golden State); Green Power Institute (GPI); Hydrostor, Inc. (Hydrostor);

Independent Energy Producers Association (IEP); Invenergy California Offshore, LLC (Invenergy California); Large Scale Solar Association (LSA); Mussey Grade Road Alliance (MGRA); Natural Resources Defense Council (NRDC); Oceantic Network (Oceantic); Offshore Wind California (OWC); Pattern Energy Group LP (Pattern); Protect Our Communities Foundation (PCF); Pacific Gas and Electric Company (PG&E); RWE Offshore Wind Holdings, LLC (RWE); San Diego County Water Authority (SDCWA) and City of San Diego, jointly; San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); Shell Energy North America (US), L.P. (Shell); Solar Energy Industries Association (SEIA); Swan Lake North Hydro, LLC (Swan Lake); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); and Vineyard Offshore, LLC (Vineyard).

Reply comments were due on June 5, 2024 and were timely filed by the following parties: ACP-CA; AReM and UC Regents, jointly; BAMx; BHE; Brightline; Cal Advocates; CalCCA; CalWEA; CEJA and Sierra Club, jointly; CEERT; CESA; EDF; Environmental Protection Information Center (EPIC); Equinor; Fervo; Form; GreenGen Storage (GreenGen); GPI; Hydrostor; IEP; Invenergy California; MGRA; NRDC; OWC; PCF; PG&E; RWE; SCE; SDCWA and City of San Diego, jointly; SDG&E; Southern California Gas Company (SoCalGas); Shell; SEIA and LSA, jointly; and Vineyard.

Solar Dynamics, LLC (Solar Dynamics) filed a motion to late-file its reply comments on June 6, 2024; the motion was granted by an ALJ ruling on May 7, 2024.

1.1. Submission Date

This portion of this proceeding was submitted on June 6, 2024, upon the filing of Solar Dynamics' reply comments.

2. Issues Before the Commission

The sole issue addressed in this decision is the implementation of AB 1373 (Stats. 2023, Ch. 367), which allows the Commission to request that DWR serve as a CPE for certain LLT resources.[5]

3. Comments of Parties

This section summarizes the content of parties' comments on the April 26, 2024 ALJ Ruling by topic area.

3.1. Resource Eligibility

The ALJ Ruling offered four resource types for consideration for centralized procurement by DWR: OSW, Out-of-State (OOS) wind, geothermal, and long duration energy storage (LDES). Parties commenting on the appropriate resource types to be procured were mixed in their opinions. One theme among a plurality of parties was to focus on OSW procurement. Several developers or representatives of particular industries prefer that the Commission require procurement of their specific LLT resource type.

Among OSW lease holders or developers, including Equinor, Golden State, Invenergy California, RWE, and Vineyard, most suggest an initial need determination for OSW. ACP-CA, Invenergy California, CalWEA, Hydrostor, and Vineyard also suggest that the eligibility criteria for resources should be expanded to include resource diversification and other public policy goals. OWC, Vineyard, and Invenergy California suggest consideration of the additional benefits of OSW, including greenhouse gas (GHG) emissions reduction goals, economic development, job creation, and other non-energy benefits. Brightline suggests that a higher need determination for OSW initially

[5] Assigned Commissioner's Amended Scoping Memo and Ruling Extending Statutory Deadline, April 18, 2024, at 3.

will help costs decline faster, which is important given the timeline for 25 GW by 2045 included in the California Energy Commission's (CEC's) Strategic Plan addressing the AB 525 (Stats. 2021, Ch.231) goals.[6]

CEJA and Sierra Club also argue that the non-energy benefits should be included in the criteria, including the social cost of carbon and air quality benefits. EDF agrees that air quality benefits should be included. PCF also argues the Commission should consider additional risk assessment factors such as location, economic risks, and environmental effects beyond carbon emissions.

CEJA and Sierra Club also argue that an important criterion should be consistency with resource needs to meet Senate Bill (SB) 100 (Stats. 2018, Ch. 312) goals. CEJA and Sierra Club support Central Procurement Entity (CPE) procurement of OSW because it can help lead to faster retirement of natural gas plants. In reply comments, Vineyard agrees. Also in replies, Invenergy and RWE point to other state policy goals, including SB 100 and AB 525, as well as major resource potential, resource diversity, cost reductions from economies of scale, and the need for significant development of common infrastructure. Vineyard and EPIC, in replies, also point to the benefits of economies of scale leading to cost reductions, and state that the cost-benefit analysis conducted to date does not adequately account for this.

BAMx seems to prefer that there not be a need determination made at this time for OSW, because the cost of transmission is too high relative to other available resources.

Form recommends that selection criteria should be weighted toward emerging technologies not yet proven on a large scale, and specifically argue for

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[6] The Final AB 525 Strategic Plan is available at the following link: https://www.energy.ca.gov/data-reports/reports/ab-525-reports-offshore-renewable-energy

the inclusion of multi-day storage technologies. Fervo argues that enhanced geothermal should be considered separately from conventional geothermal. AEU agrees. Fervo also argues that reliability should be made an explicit value when evaluating resources over multiple days, because geothermal can provide night-time and winter reliability better than other resources. Fervo suggests that the prioritization criteria highlight grid reliability and regional transmission needs. BHE points out that there should potentially be different treatment for the development of a geothermal field as distinct from a single project, and that initial development of the field is a heavier lift than buildout of a project once the field is already developed.

MGRA argues that pumped storage hydroelectric (PSH) resources should be eligible for consideration, but not the San Vicente project put forward by the City of San Diego and SDCWA, because it is not cost-effective or cost-competitive. PCF also opposes the San Vicente project, and would like to see public ownership explored for other PSH projects. MGRA is concerned that the costs assumed for PSH in RESOLVE modeling do not reflect the costs of pumped storage in California and the site-specific characteristics make a one-size-fits-all approach inappropriate. SDCWA and the City of San Diego argue that the San Vicente project should be procured by DWR, as contemplated in the language of AB 1373, which provides for characteristics of PSH projects that fit the San Vicente situation. Swan Lake advocates for the procurement of its PSH project in Oregon, even though it does not meet the criteria in AB 1373 that a PSH project be "directly appropriated funding by the state before January 1, 2023."[7]

[7] *See* Section 454.52(h)(2).

PCF also argues that OSW and OOS wind are too expensive, and geothermal is already well enough developed and does not need CPE support.

Hydrostor points out that LDES is a broad category, and due to this, each individual technology is valued less in the rating of numerous technologies.

CEERT argues for the inclusion of concentrating solar power (CSP) technologies. Solar Dynamics agrees in reply comments, and suggests that the Commission reassess CSP to reflect the state of CSP technology today and include it in RESOLVE modeling in future IRP cycles.

BAC and GPI argue that bioenergy should be evaluated as a clean firm resource, while GPI acknowledges that emitting resources do not qualify under the language of AB 1373. Still, they argue that these resources should be considered from a broader perspective beyond AB 1373.

Pattern argues that OOS wind should not be considered a proven technology with no opportunity for cost declines, because the use of a CPE may assist in creating cost savings. Pattern also argues that DWR can be considered an anchor tenant to help develop appropriate transmission buildout.

CAISO points to statements within the Commission staff analysis attached to the ALJ Ruling referring to the SunZia project in particular, to conclude that it is unclear that centralized procurement is necessary, given examples of merchant-based transmission moving forward with LSE-level contract commitments. CAISO clarifies that the financing model used for the SunZia project is not applicable for transmission within the CAISO footprint and was specifically designed to enhance opportunities for construction of new transmission in locations currently outside of the CAISO balancing area to facilitate delivery of critically needed resources. In reply comments, AReM and UC argue that there is no consensus for how transmission costs should be treated

as part of CPE procurement, and recommend that the Commission set up a process to explore these issues in greater detail. In the meantime, AReM and UC recommend that OOS wind not be eligible for procurement by DWR.

LSE representatives commented with mixed opinions. CalCCA, PG&E, and SCE suggest only considering OSW for centralized procurement, and not any other resource type, and CalCCA would support it only if it does not interrupt individual LSE procurement. Calpine states that the CPE should not be asked to procure resource types that LSEs are already procuring. SDG&E suggests that more criteria should be included prior to making a determination. CalCCA also suggests the five-year lead-time requirement for resources to qualify for use of the CPE in AB 1373 should not include transmission or interconnection time, but rather only time for the resource itself to come online. In reply comments, CalCCA states that OOS wind and geothermal have not been demonstrated to take more than five years and LSEs have already demonstrated the ability to procure them individually. Fervo, however, provides evidence for geothermal projects taking five years or more to develop, arguing that the average is closer to seven years.

PG&E prefers no technology carve-outs, especially for pumped storage. PG&E also comments that the criteria set forth in the ALJ Ruling should be more clearly defined and include more comprehensive condition descriptions.

SCE recommends that the eligibility criteria include the primary question about whether LSEs can procure on their own. SCE suggests that it is premature to conclude that LSEs can't procure any of the resources. SCE also suggests that the investor-owned utilities (IOUs) should be the CPE instead of DWR. If the Commission moves forward with DWR CPE procurement with technology carve-outs, which SCE does not suggest, then SCE proposes that the technology

types be limited to those that are not widely demonstrated. However, SCE also argues that procurement of emerging technologies is also questionable, stating that it is unclear why customers should pay to transform an industry that is not commercially ready, given the many affordability pressures facing customers right now.

CalCCA recommends including resource diversity as an explicit criterion, as do ACP-CA, CEERT, and Invenergy. In reply comments, Fervo agrees. CalCCA comments that there can be many reasons for otherwise cost-effective resources not being procured in sufficient volumes, including limited availability, transmission and interconnection backlogs, deliverability uncertainty, and large infrastructure needs (such as ports for OSW). CalCCA recommended that the Commission take on these challenges directly, rather than relying on a CPE.

Shell argues that a CPE should be used only when a compelling need to overcome market failures can be identified, such as for OSW currently.

ACP-CA suggests that the CPE structure be assessed for its ability to overcome other challenges/hurdles such as port and transmission infrastructure investment, and expand cost-effectiveness to include economic reliability and GHG benefits over the course of the energy transition.

Finally, IEP prefers that the Commission not list chosen resource types, but rather list only the criteria or attributes of the resources. In reply comments, ACP-CA argues that AB 1373 specifically requires the Commission to "specify resources"[8] for DWR central procurement, and thus attributes are not enough.

[8] *See* Section 454.52(a)(4)(B).

In reply comments, SoCalGas suggests that carbon capture and storage (CCS) and gas-to-hydrogen combustion are emerging technologies providing clean firm electricity that should be considered for procurement by a CPE. Calpine and MGRA also raised CCS as an option in their opening comments, whereas UCS points out that procuring emitting resources by the CPE is prohibited by the language of AB 1373, which states that DWR can only procure a resource that does not "increase the state's dependence on any fossil fuel-based resources," "does not generate electricity using fossil fuels or fuels derived from fossil fuels," and "does not use combustion to generate electricity, unless that combustion use is ancillary and necessary to facilitate geothermal electricity generation."[9] CalCCA and NRDC also point out in replies that combustion and emitting technologies are not eligible under the AB 1373 provisions. IEP suggests that these technologies be considered in the future outside of AB 1373.

3.2. Need Determination

On the topic of the amount of procurement of particular resources that the Commission should request from the CPE, parties have presented very mixed opinions.

While a good number of parties comment that the preferred system plan (PSP) portfolio is a reasonable place to start for determining need for the various resource types considered, some parties raised specific concerns about that as a need determination source.

PG&E does not support the PSP as a starting point for an OSW need determination, PG&E does not support centralized procurement by DWR for other technology types for a need determination by September 1, 2024, but

[9] *See* Section 454.52(h)(1)(D) and (E).

argues that the PSP portfolio is a reasonable basis for considering use of the CPE for such resources at a later time in this proceeding, or in a successor proceeding. PG&E also would prefer that the procurement be done based on attributes that the technology type fulfills, broken down into daily, monthly, or yearly generation profiles.

SCE points out that inclusion of a resource in individual LSE IRPs does not necessarily indicate a need, either for reliability or GHG reduction purposes. SCE also argues that the cost-benefit analysis presented in the ALJ Ruling does not help determine the optimal amount of OSW for the portfolio, but rather just analyzes the various amounts of OSW forced into the portfolio. SCE does support 1 GW of OSW as a prudent start to use DWR as a CPE, arguing this amount is large enough to support a viable project but small enough to minimize risks to customers. PG&E supports DWR soliciting for procurement of up to 3 GW of OSW, but urges the adoption of off-ramps in the event that the projects are too expensive.

SCE comments that there is no need for cost-benefit analysis to determine need, but it can be useful for informing a confidential cost cap and an initial procurement limit for DWR. SCE also states that a cost-benefit analysis alone should not serve as a minimum basis for a non-zero need determination. Instead, SCE suggests that IRP procurement requirements should be driven by matching system needs informed by IRP modeling with the resource attributes that must be satisfied by the procurement, rather than requiring resource-specific technology carve-outs. SCE argues that deviating from competitive, attribute-based procurement often results in uneconomic or suboptimal cost results for consumers. Thus, SCE argues that procurement should be limited to the amount

required to bring an emerging technology to the point of being commercially viable.

SDG&E does not support a need determination by specific technology. Rather, SDG&E argues that all eligible resources should be allocated to participate in a least-cost solicitation, with the best-priced resources selected.

CalCCA is concerned that using the PSP resource amounts has risks, including outdated data, especially for OSW. CC Power similarly argues that the OSW cost estimates are too low in the National Renewable Energy Laboratory Annual Technology Baseline. CalCCA also argues that the PSP does not adequately consider LSE planned capacity, and argues that any need determination made by the Commission here must adequately consider the LSEs' right to self-procure ahead of authorizing any centralized procurement. Ultimately, CalCCA argues that the Commission should delay making any need determination until more recent LSE procurement data is available, stating that more OSW through 2028 will be represented than was included in Table 1 of the ALJ Ruling.

LSA generally supports using the PSP as a starting point, except for the OSW amount because it was not selected by RESOLVE but rather forced in on the basis of LSE plans. SEIA supports the Commission making a need determination for OSW of up to 4.5 GW, but proceeding with caution. Invenergy suggests a 4.5 GW minimum, but a total target of 10 GW.

Calpine argues that the Commission should use the least-cost portfolio and not the core portfolio that was selected as the PSP, to determine a need for CPE procurement. Calpine would support an OSW need determination of 1 GW now, and no more than 4.5 GW, stating that OSW is the only resource for which the case for CPE procurement is clear.

IEP supports 4.5 GW of OSW as a need determination through the PSP, because it aligns with the amount of transmission planning at the CAISO and limits risks to ratepayers by not over-committing to a resource with potentially uncertain procurement costs. IEP would also support an amount of up to 4 GW of OOS wind, because that represents the difference between the PSP portfolio amounts and those planned to be procured by the LSEs in their plans.

BHE makes a similar argument that the amount of procurement ordered through a CPE should be the gap between the PSP resource amounts and those already procured in response to the mid-term reliability (MTR) procurement order (D.21-06-035), in order to prevent a tight market for firm capacity.

The majority of the parties representing OSW interests support a 10 GW need determination for OSW development by 2035. Vineyard, Golden State, and Equinor argue that because 10 GW is the full lease amount so far, it would send the strongest market signal that California wants to develop the potential. Oceantic also agrees. In reply comments, Invenergy argues that California will only achieve the necessary economies of scale to reduce costs and maximize benefits if the initial need determination is robust, and also states that the 10 GW need not be procured all at once.

Golden State and OWC also support the rationale for procuring LLTs as a "public good"[10] on behalf of all ratepayers. Vineyard also suggests that the solicitations for OSW can be broken up into 2 GW tranches evenly spaced out through 2035. Equinor supports the provision that DWR not be required to procure the full amount of the need determination, and that multiple successive

[10] See April 26, 2024 ALJ Ruling at 23.

solicitations could be prudent. CUE/CURE also support a need determination of 10 GW of OSW by 2035.

CalWEA also supports 10 GW of OSW as a need determination, stating that the 4.5 GW in the PSP is not enough. CalWEA argues that updates to RESOLVE would likely show, particularly with reduced transmission costs, that the 10 GW quantity can be delivered at reasonable cost and without significant cost risk.

OWC also supports a 10 GW OSW need determination, arguing that the analysis presented so far does not adequately value diversity benefits. OWC also wants additional consideration of increased federal funding available, and other contributions to the public good, including economic development and job creation. In addition, OWC argues that the Commission should also consider electricity needs to reach the goals in SB 100, the 2022 California Air Resources Board (CARB) Scoping Plan, which calls for 20 GW of OSW by 2045, and the CEC's AB 525 report, calling for 25 GW of OSW by 2045. Brightline also points to the AB 525 report on OSW, stating that the PSP should not be the exclusive source of need.

EDF also supports a need determination of 7.6 to 10 GW of OSW by 2035 to ensure that leases already awarded reach their full capacity. EDF also comments that the need determination should take a least-regrets approach and build as much as possible, then leverage the tools available to DWR as the CPE to help protect ratepayers so they do not over-buy in the near term. EDF would also support using DWR as the CPE to procure LDES and geothermal later. In reply comments, EDF also points out that the 7.6 GW-10 GW range represents full lease capacity and the cost-effectiveness analysis was too limited temporally to capture the full benefit of OSW over its expected useful life. EDF argues that

procurement of OSW is needed now in order to ensure cost-effective procurement through 2045.

In reply comments, EPIC supports a 7.6 GW need determination for OSW as it was shown in the Commission staff's cost-benefit analysis to represent the level after which ratepayer risks increase. Therefore, EPIC argues this is the minimum need that should be found, and AB 1373 was passed to catalyze the OSW industry, necessitating a "leap of faith."[11]

NRDC comments that the staff analysis is a step in the right direction and a reasonable basis for a need determination currently.

CESA is concerned that the PSP understates the need for LDES technologies and the capacity expansion model does not include sufficient LDES durations and technologies as candidate resources with associated cost figures. Hydrostor comments that the PSP was not developed with the intent to support LLT procurement by a CPE. Hydrostor is particularly concerned about technology neutrality in the LDES category, especially those technologies that are not lithium-ion batteries. In reply comments, Hydrostor points out that many parties arguing in comments that LSEs can procure LDES on their own appear to be referring mainly or exclusively to lithium-ion batteries, and that this is not true for other diverse and emerging LDES technologies.

GreenGen, in reply comments, argues that analysis of the LDES category has been heavily weighted toward lithium-ion batteries, which have a much shorter asset life and do not provide critical grid stability services provided by turbine-based technologies like PSH. GreenGen also points out that PSH

[11] EPIC June 5, 2024 Reply Comments at 4.

technologies do not degrade with each cycle and have useful lives of more than 50 years, which will help stabilize costs over the long term.

AReM argues that lithium-ion batteries should not be eligible to be purchased by the CPE; instead, DWR should focus on other LDES technology types in need of economies of scale and with known longer development times. Hydrostor agrees.

CESA argues that the LDES procurement to date is insufficient to meet PSP requirements, and therefore a need determination should be made for LDES to be procured by DWR.

CESA points to a joint study conducted by Energy and Environmental Economics (E3), Form Energy, and the CEC[12] that reflects the LDES candidate resources with longer durations and accurately reflects the impact of multi-day weather events, modeling the multi-day inter-temporal effects within the resource selection optimization. CESA and Form both argue that intra-day and multi-day storage will likely play an essential role in decarbonizing the electricity sector effectively, noting that the Joint CEC study identifies the need for 5-37 GW of LDES by 2045.

Form further argues that the fact that a specific cost-benefit analysis was not conducted for non-OSW resource types should not prevent the Commission from making a need determination for the other resource types. Form recommends CPE procurement of at least 1 GW of emerging LDES technologies by 2031, including 500 megawatts (MW) of multi-day storage, with at least 2 GW by 2035.

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[12] The cited study is titled "Assessing the Value of Long-Duration Energy Storage in California." California Energy Commission Publication Number CEC-500-24-003.

AEU comments that there was a disparity between the analysis done for OSW and other resource types, and is particularly concerned that the use of 8-hour lithium-ion batteries as a proxy for other resources biases the analysis against geothermal system and LDES. AEU strongly recommends that enhanced or advanced geothermal systems be treated as a separate resource type.

AEU also argues that AB 1373 does not make reference to a quantity of resources, but rather requires the Commission to specify the resources that should be procured to meet that need. Thus, AEU argues that the Commission need not specify the exact quantity of need, but can do this during the six-month period before making the request to DWR to procure. Thereafter, AEU argues that DWR has the flexibility to structure the number and timing of competitive solicitations.

CEJA and Sierra Club comment that the PSP is a reasonable starting point for a need determination, but the high gas retirement scenario should be used to better reflect SB 100 goals. CEJA and Sierra Club also comments that the cost-benefit analysis presented is incomplete, because it fails to meaningfully account for the economic benefits of public entity procurement and the non-energy benefits that result from the construction of diverse resources, including lower air pollution and GHG reductions.

PCF comments that no threshold has been met in the analysis to trigger CPE procurement. PCF especially opposes the CPE being used to procure OSW and OOS wind, but may support LDES. PCF would recommend that the Commission consider authorizing DWR to build and own any additional PSH resources located in California that are cost-effective, reduce GHG emissions, and determined to be needed. PCF further argues that geothermal and PSH

resources are already well developed and procurement by DWR would merely serve to reallocate those already-in-use resources to other buyers.

Cal Advocates supports a non-zero need determination for DWR, and comments that the cost-benefit analysis conducted on OSW offers a reasonable basis to conclude that higher levels of OSW are more likely to produce negative net benefits for ratepayers under current assumptions. TURN supports that the need determination be made with each IRP cycle when considering the PSP to be adopted.

3.3. Relationship to Load-Serving Entity (LSE) Procurement

A majority of parties in comments support the concept that the LLT procurement by DWR as a CPE should be conducted as a public good.[13] IOUs, CalCCA, most trade associations, and LLT developers all support this as a general principle. The notable exception is Cal Advocates, which points out that GHG reduction is a fundamental statutory obligation of the IRP process, with or without centralized procurement.

Cal Advocates supports the Commission making a small initial need determination by September 1, 2024, and reevaluating need during the consideration of future PSP portfolios. Cal Advocates further points out that actual cost reductions achieved by DWR procuring an initial tranche of procurement of OSW could move the resource closer to cost-competitiveness in individual LSE solicitations; further volumes of OSW could then be obtained by LSEs without centralized procurement.

Another theme of agreement in the majority of comments with respect to the relationship of DWR centralized procurement and that of LSEs was on the

[13] *See* April 26, 2024 ALJ Ruling at 23.

issue of allowing a six-month period following the need determination for publicly-owned utilities (POUs) to elect to participate in a DWR solicitation, prior to DWR initiating the solicitation.

Many parties also agreed that the need determination by the Commission should be reconsidered with every IRP cycle, including PG&E, TURN, Invenergy, LSA, Shell, and Vineyard, to name a few. Equinor prefers that the solicitation process by DWR be decoupled and designed outside of the context of PSP adoption and the IRP cycles, and tracked separately. BHE and ACP-CA believe the PSP should be used with flexibility for a more frequent need determination, if needed. GPI opposes this decoupling in reply comments, particularly because assessing need as part of the PSP development process will ensure that transmission development is evaluated at the same time. ACP-CA and Invenergy also request that need determinations not be reduced in subsequent IRP cycles, once made, in order to avoid market confusion.

A more controversial topic in the area of the relationship between potential DWR procurement and LSE procurement is the subject of whether individual LSEs should be allowed to opt out of paying for their share of DWR procurement, in favor of making their separate contracts for needed resources.

CalCCA argues that the Commission must adhere to provisions in Sections 454.51 and 454.52, which include the right of self-procurement by CCAs. CalCCA argues that these provisions mean that there should be an opt-out opportunity for LSEs, in the six-month period between when the Commission makes a need determination and when the request it made to DWR to procure. SDG&E also supports the opportunity for LSEs to opt out. MGRA argues that LSEs should be allowed to opt out in order not to penalize early actors.

SCE and PG&E oppose the idea that LSEs should be allowed to opt out, as do Calpine, NRDC, GPI, and Vineyard. In reply comments, PG&E argues that LSEs can still procure and coordinate with DWR to avoid duplicative procurement. SCE argues that the nonbypassable charge to recover CPE procurement costs should be imposed on all LSE customers. SCE argues that, by definition, a need determination for procurement by a CPE should only be made by the Commission when LSEs are unable to procure a necessary LLT resource.

AReM and UC Regents, in reply comments, state that the size and complexity of LLT projects is beyond the ability of individual LSEs to handle, so procurement would be more cost-effectively and efficiently undertaken by DWR. CalCCA disputes a similar points made by CUE/CURE, by citing to joint powers authority procurement such as that described by CC Power in its comments.

CC Power points out that even though most parties agree that OSW is the best candidate for CPE procurement, in part because the LSEs have not yet procured it, CC Power has already initiated a solicitation for OSW and consideration of next steps. In addition, CC Power has signed a memorandum of understanding (MOU) with the CADEMO OSW demonstration project, which will develop four floating turbines using existing technology in an area where some electrical infrastructure already exists due to its location near historical oil exploration equipment.

AEU argues that participation in CPE procurement should be optional for POUs, CCAs, and other LSEs, and that DWR should use a subscription model for participation in its contracting.

Invenergy suggests that the Commission plan for a transition from the CPE to LSE procurement in areas where a need is found but the CPE may no longer be needed.

The CAISO comments chiefly expressed concern that the CPE procurement be reflected in IRP portfolios so that the CAISO can take the resources into account in its annual transmission planning. GPI also commented that the impact of the CPE need determination on the Transmission Planning Process (TPP) is unclear. GPI is concerned that offsetting the need determination from PSP adoption may impact IRP efficiency, pointing out that that the recent PSP may not align with this need determination for LLT resources. GPI is also concerned about the interaction with the reliable and clean power procurement program (RCPPP) expected to be considered in this proceeding later this year. GPI comments that the LLT need determination for DWR should be assessed in the near term on the same timeframe as other procurement orders prior to the adoption of the RCPPP.

3.4. Allocation of Costs and Benefits

The chief recommendation in the ALJ Ruling around allocation of costs and benefits was that the allocation methodology could mirror the one adopted recently related to the costs for the extension of the Diablo Canyon Power Plant (Diablo Canyon). The method is similar to the Cost Allocation Mechanism (CAM) originally authorized in D.06-07-029, except that costs are spread uniformly across all LSEs subject to the Commission's Resource Adequacy authority, rather than being differentiated by IOU territory. The ALJ Ruling proposed using a 12-month coincident peak lead method to allocate costs and benefits to each LSE's customers.

In its comments, SCE suggests that cost and benefit allocation could be one based on energy load share if the purpose of the CPE procurement is GHG reduction. Otherwise, if the procurement is for reliability purposes, then SCE suggests that the proposed 12-month peak allocation is appropriate. PG&E and

SDG&E agree with the proposed 12-month coincident peak load. In addition, PG&E specifies that costs are allocated based on forecasting for the applicable year, as opposed to the most recent full year, to remain consistent with the cost allocation for the costs of keeping Diablo Canyon open. CalWEA suggests that the 24-hour slice-of-day framework in resource adequacy should be used as a methodology source for allocation, rather than peak load.

CEJA and Siera Club argue that the CAM for resource adequacy has not been entirely successful, though they do not define their criteria, and therefore they suggest the Commission proceed with caution to ensure environmental, equity, and ratepayer protections are upheld.

Parties were also concerned about the provisions allowing for POUs and/or LSEs to elect to purchase additional resources from DWR on a voluntary basis, beyond the need determination made by the Commission.

PG&E suggests that LSEs and POUs submit their requests for additional procurement by DWR on a capacity basis. SCE suggests that incremental costs should be separately tracked so they are not imposed on other non-participating LSE customers. Further, SCE argues that additional procurement for POUs and other LSEs should be allocated based on the marginal capacity procured. SDG&E agrees that incremental costs should be allocated solely to the LSEs/POUs to avoid any cost shift onto other customers. CalCCA agrees, stating that the Commission must ensure that additional volumes do not increase the costs to those that have central procurement costs allocated to them but did not request additional volumes.

Cal Advocates argues that the Commission should count any voluntary participation from POUs within the CAISO footprint towards the total need determination for DWR centralized procurement. Then, according to Cal

Advocates, any participation by non-CAISO POUs should not reduce the total CAISO footprint need determination, as a general matter.

Shell argues that it would be more appropriate, in this case, to allocate the costs and benefits in a similar way to the voluntary auction/market offer (VAMO) process used to allocate the voluntary purchase of renewables from IOUs by other LSEs. Shell also argues that all attributes (energy, capacity, renewable energy credits, and GHG reduction value) should be allocated to LSEs.

NRDC argues that DWR can design its solicitation and contracting process in such a way as to allow LSEs to procure resources beyond the levels in the Commission's need determination.

Several parties also commented on the likely need for non-energy-related costs, particularly for infrastructure related to OSW development. SCE suggests there should be a distinction made in the solicitation process for costs directly related to the electric system and its development which can be recovered through electric rates and those other costs, such as port and manufacturing facility infrastructure, which are not appropriate to be recovered in electric rates. For these reasons, SCE supports the development of cost caps. SDG&E suggests that these related infrastructure costs be included in the net present value (NPV) calculations when ranking bids. CalCCA suggests that any costs incurred by developers must be included in the bids, and be part of the bid selection process. However, CalCCA argues that the Commission must then determine if infrastructure costs are to be separate from the contract for the generation resource. Form suggests that the infrastructure costs should be considered alongside bids from resources that do not require these costs, in order to fairly compare costs.

CAISO also commented on the transmission costs associated with OSW development. CAISO communicates its commitment to both seeking to prudently manage expenditures that could be the subject of cost recovery processes, as well as providing industry transparency on the pace of transmission development activities and associated cost exposure.

Cal Advocates comments that adding additional costs for port infrastructure to the net benefit analysis reduces the possibility that any OSW is cost-effective.

Cal Advocates also brings up the idea of potentially assigning DWR as the backstop procurement entity in the event that LSEs fail to meet their LLT procurement requirements in D.21-06-035, as amended by D.22-02-004 and D.24-02-047. SDG&E agrees that DWR should be asked to provide backstop procurement for those MTR LLT resources in the event that LSEs fail to procure their required share. AReM also comments that DWR could be an effective backstop procurement entity. UCS comments that the Commission should clarify whether DWR is acting in a "frontstop" or a "backstop" capacity.[14] For example, UCS argues that DWR procurement of OSW would be "frontstop," whereas DWR may want to act as a backstop for OOS wind.

3.5. Procurement Process and Timeline

The ALJ Ruling proposed an application process for the Commission to consider whether to authorize cost recovery through a nonbypassable charge for the resources procured by DWR. Parties were fairly split on whether an application is appropriate or whether a Tier 3 advice letter should be used for Commission approval of any contracts.

[14] UCS Opening Comments, May 24, 2024, at 2-3.

SCE, PG&E, and SCE all support the application process, as does CalCCA. TURN, CEJA, and Sierra Club agree.

Numerous parties state that they would prefer a Tier 3 advice letter as the vehicle, including Equinor, Invenergy, ACP-CA, and Hydrostor. Cal Advocates would also be supportive of a Tier 3 advice letter process. Form suggests that an application is appropriate for DWR procurement, but a Tier 3 advice letter for IOU procurement.

Several parties comment that DWR may not be as experienced in handling large solicitations as the IOUs, and the IOUs should be considered to assist DWR. Form makes this point, as does PG&E. SCE suggests that the Commission should consider requesting an IOU to assist DWR in conducting the solicitation, bid evaluation, and/or contract negotiation, with reimbursement for costs by DWR once determined as reasonable by the Commission. GPI suggests that DWR should not be the CPE because of its track record for expensive contracts. GPI suggests instead that the CPE structure in the resource adequacy program, where the IOUs are required to establish independent entities with firewalls to their internal procurement activities, may be the best approach for the LLT resource CPE.

Numerous parties also request that there be a process to develop pro forma contracts or other materials prior to DWR soliciting for any contracts. PG&E comments that DWR, Commission staff, IOUs and other LSE representatives should develop a contract structure, including a pro-forma contract, to help developers understand expected terms and considerations. PG&E argues this will help developers form their bids in a solicitation. PG&E also suggests that protocols should be set up for project eligibility, such as CAISO queue position, land rights, federal lease agreements, etc. SDG&E would

support a workshop process for the development of a CPE contract template. CalCCA suggests that prior to initiating procurement activities, DWR should provide its procurement plan, including timelines and contract structures, on the record before the Commission, so that parties can weigh in before the Commission makes a final determination and DWR begins any procurement activities.

In reply comments, ACP-CA disagrees that DWR needs to present a detailed plan before proceeding with procurement, arguing that the AB 1373 requirements are already sufficiently stringent and comprehensive.

In opening comments, CalCCA also stresses the importance of off-ramps baked into the procurement plan. SCE agrees, and stresses the importance of guardrails as part of the DWR solicitation process, to minimize risks to customers. SCE specifically mentions the following elements: use of a competitive solicitation process, establishment of a procurement review group (PRG), Commission approval, flexibility to procure less than the maximum identified need, procurement limits, and a confidential cost cap based on IRP assumptions, industry data, and studies. SCE states that the cost cap can be kept confidential so that bidders do not raise their bids to the level just below the cap. BAMx agrees in reply comments.

Many parties in comments oppose the use of a cost cap, whether confidential or not, including ACP-CA, Equinor, Golden State, Oceantic, and Vineyard. Oceantic argues that cost caps would interfere with potential developer bidding that can help illustrate the risk, value, and opportunities. Oceantic also argues that ratepayers will be protected from bids that are too high by the fact that DWR will not be required to purchase up to the total need determination amount, and thus DWR and the Commission may decide to reject

bids after evaluating the results of the solicitation. Vineyard agrees with these points in reply comments.

LSA stresses the importance of offramps to minimize risk to consumers.

Another issue discussed in the ALJ Ruling was a structure for a PRG designed to advise DWR on procurement activities and outcomes. The ALJ Ruling suggested that the PRG for DWR should be made up of non-market participants.

SCE strongly advises that the Commission consider allowing LSE representatives to serve on the PRG to DWR, as the LSEs have a vested interest in representing their customers. CalCCA agrees and suggests that the PRG should include at least one representative from each LSE type, including non-market participant CCA representatives.

Cal Advocates suggests that the PRG for DWR be modeled off of IOU PRGs. If the Commission approves a project or multiple projects, Cal Advocates suggests that DWR continue to meet with the PRG to provide progress updates and host any additional meetings for delays, disputes, or any changes to the contract price.

CEJA and Sierra Club suggest that the PRG involve impacted communities, including an option where a community member or organization can participate without reviewing confidential information. Generally, CEJA and Sierra Club suggest that DWR should work with local communities for consideration of their input on contracts. In reply comments, Brightline specifically recommends separate engagement with Tribal Nations. Brightline also suggests that the Commission encourage DWR to take into account the U.S. Department of Energy's (DOE) requirements that applicant projects include Community Benefit Plans.

DOW suggests that the PRG include staff from the California Department of Fish and Wildlife and the Governor's Office of Planning and Research, as well as non-market participants to provide technical assistance for evaluating potential for environmental and land-use conflicts.

IEP recommends a diverse PRG with industry and community representation.

Another issue parties commented on is the timing of solicitations. ACP-CA, Form, Oceantic, and CESA state that the timeline in the ALJ Ruling is too long for OSW. Golden State and RWE recommend an initial solicitation no sooner than 2026 but no later than 2028. Oceantic suggests that the first solicitation be in 2025. RWE and Oceantic would prefer solicitations on a periodic schedule, around every two years, for additional capacity after the initial solicitation. Equinor also supports periodic solicitations.

Several parties brought up the concept of DWR soliciting for an open-book contract structure, where developers would be paid based on actual costs, with an agreed-upon profit margin. Some parties argue this could be a good option for OSW, since the costs are completely unknown. The approach would be similar to cost-of-service regulation of utilities, where at least initially the contract cost would be transparent to the Commission. BHE, CalWEA, CEERT, IEP, and TURN recommend that the Commission consider this option. SCE agrees in reply comments, and also recommends cost benchmarks and potential off-ramps to protect customers. PG&E also wants the procurement to show a net benefit for customers, along with supporting off-ramps or guardrails.

TURN also generally comments that the Commissions should encourage DWR to consider a variety of alternative contract structures designed to lower costs and maximize ratepayer benefits. GreenGen agrees in reply comments.

Finally, Cal Advocates recommends that DWR be required to procure bridge capacity in the event of project delays for its assigned procurement.

4. Discussion

This section discusses the determinations that the Commission is making for procurement of several LLT electricity resources in advance of the September 1, 2024 deadline in AB 1373.

AB 1373, codified as Section 454.52(a)(4), directs that the Commission "determine if there is a need for the procurement of eligible energy resources based on a review of the integrated resource plans submitted by load-serving entities in compliance with the requirements of this section and Section 454.53 and the progress towards meeting the portfolio of resources identified pursuant to subdivision (a) of Section 454.51."

First, as proposed in the ALJ Ruling and supported by the vast majority of parties filing comments, the Commission will plan to evaluate the need for procurement of LLT resources by a CPE on behalf of LSEs under the Commission's IRP purview with every IRP cycle when the PSP portfolio is being considered. Because numerous factors associated with electricity planning are changing constantly, including cost assumptions, available technologies, and progress toward GHG emissions reduction goals, it is logical that the need for CPE investment in LLT resources should be considered periodically.

Second, the ALJ Ruling also proposed that any non-zero need determination made by the Commission be a maximum procurement amount, but that DWR not be required to procure the full amount if the cost is not reasonable. In other words, DWR would solicit up to the maximum amount requested by the Commission, but DWR could procure any amount less than that, including zero. The ALJ Ruling proposed that DWR not procure these

resources at any cost. Almost every party agreed with this proposal in comments. This is also the simplest form of cost containment we can provide for ratepayers in this endeavor, though it is not the only cost containment measure contemplated herein (*e.g.,* Commission review of contracts, pursuant to this decision).

If developers do not offer contract pricing that is attractive from a ratepayer perspective at the time of the offers, their resources are not guaranteed to be bought. Therefore, we will include this policy in our need determinations herein. All amounts will be maximums, with zero as the minimum.

4.1. Resource Types to be Procured

AB 1373, in the sections codified as Section 454.52(h)(1)-(2), defines criteria for resources that are eligible to be centrally procured, as follows:

> (1) Only a resource that meets all the following requirements is eligible to be procured by the Department of Water Resources pursuant to this section:
>
> (A) The resource directly supports attainment of the goals specified in Section 454.53 without increasing the state's dependence on any fossil fuel-based resources.
>
> (B) The resource is determined by the Commission to not be under contract at sufficient levels as shown in load-serving entities' most recent individual integrated resources plans submitted to and reviewed by the Commission pursuant to this section to achieve the goals specified in Section 454.53.
>
> (C) The resource has a construction and development lead time of at least five years.
>
> (D) The resource does not generate electricity using fossil fuels or fuels derived from fossil fuels.
>
> (E) The resource does not use combustion to generate electricity, unless that combustion use is ancillary and

necessary to facilitate geothermal electricity generation.

(2) Resources from a pumped hydroelectric facility may be procured by the Department of Water Resources pursuant to this section if the pumped hydroelectric facility does not exceed 500 megawatts and has been directly appropriated funding by the state before January 1, 2023.

The ALJ Ruling recommended that the Commission consider centralized procurement for a LLT resource that provides resource diversity, is needed to meet the goals of Section 454.53, and has already been identified as needed in a PSP portfolio, if it also provides one or both of the following benefits:

- Addresses procurement challenges for existing technologies, such as when LSEs are currently unable or unwilling to procure the resource individually or at the scale required, because of the size and/or risk profile of the technology; or
- Supports market transformation for emerging technologies, where the initial procurement creates the potential for future cost reductions through economies of scale or learning about the best ways to conduct resource development.

The ALJ Ruling explicitly identified four potential resource types that meet the criteria given in the statute: OSW, geothermal, LDES, and OOS wind. Each of these resource types has already been identified as part of the most recently-adopted PSP portfolio in D.24-02-047.

We appreciate many parties' thoughtful comments on the appropriate criteria to be used to select the candidate LLT resources to be procured by a CPE. We agree with the many parties who asked us to explicitly consider resource diversity as an important and primary criterion to consider in evaluating the need for specific LLT resources. We also note that Section 454.52(a)(1)(J) states

that LSEs must "maintain a diverse portfolio of energy resources, which may include eligible energy resources procured by the [DWR]."

Section 454.52(a)(2)(B) also states that "the commission may approve procurement of resource types that will reduce the overall emissions of greenhouse gases from the electricity sector and meet the other goals specified in paragraph (1), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan."[15]

This represents a second important criterion for the selection of LLT resources to be centrally procured. We are intentionally focused on resources that we believe could be important to the electricity sector as a whole in achieving California's SB 100 goals by 2045, but which will be inherently more expensive due to their emerging nature and the fact that they are not currently commercially available at competitive prices.

In this way, our action with respect to the LLT resources selected in this decision is intended to bring about market transformation of particular technologies, similar to the manner in which early IOU ratepayer investments authorized via Commission-authorized centralized procurement in solar, wind, and battery storage helped bring down the cost of those technologies in California and worldwide.

Herein, we are explicitly asking LSE ratepayers, through the central procurement mechanism, again to take on the responsibility for making an initial investment in several promising emerging technologies that may prove to be

[15] Paragraph (1) refers to the requirement for LSEs to periodically submit individual IRPs, and to address certain policy requirements within them, including, but not limited to, minimizing bill impacts, maintaining just and reasonable rates, and meeting GHG and RPS goals.

important for achieving SB 100 GHG reduction goals in the electricity sector, as public goods on behalf of all ratepayers under our IRP purview, regardless of their specific LSE.

Because we are taking this approach to market transformation of particular electricity resources, we necessarily must be resource-specific. Once these technologies are available in a widespread manner at lower costs, we will expect them to be able to compete favorably in procurement by LSEs and to be procured in further significant quantities. But right now, the resources we are selecting are inherently more expensive and would be unlikely to be selected in volumes high enough to lead to market transformation by an individual LSE in a least-cost procurement solicitation.

We do expect that some LSEs may begin or have already begun to procure some of these LLT resources in some quantities, and nothing in this decision is intended to prevent or prohibit such procurement. Rather, our approach anticipates that some LSE procurement may occur. In the future, when LSE procurement of these resources is becoming more common, the Commission can limit, reduce, or refine centralized procurement for certain LLT types.

In authorizing procurement up to the amounts detailed in this decision, we seek to create the opportunity for these resources to bid on a competitive basis in order to facilitate this potential market transformation. We do not determine that this volume of these resources is necessary to meet our SB 100 goals.

We also acknowledge the points raised primarily by CalCCA that we are required by Section 454.51(d) to "permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration and diverse resources need identified in subdivision (a)." Subdivision (a) refers to the identification by the Commission of a "diverse and balanced portfolio of

resources needed to ensure a reliability electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner."

The November 1, 2022 individual IRP filings of LSEs represented the LSE proposals for procuring the diverse resources considered herein. We acknowledge that numerous LSEs, including CCAs, have identified planned resources in their November 1, 2022 individual IRP filings showing an intent to purchase a number of emerging resources, including chiefly OSW, LDES, and geothermal resources. CCAs have shown great initiative in response to the D.21-06-035 requirements and in bringing the CADEMO project under a memorandum of understanding that could lead to a contract. Our intent is not to interfere with any of these efforts or penalize early action by some LSEs for some resources.

At the same time, we also must harmonize the self-provision opportunity for CCAs with the criteria for LLT resources to qualify for CPE procurement that were added by AB 1373, including: "the resource is determined by the commission to not be under contract at sufficient levels as shown in load-serving entities' most recent individual integrated resource plans submitted to and reviewed by the commission pursuant to this section to achieve the goals specific in Section 454.53 [SB 100 goals]."

While we acknowledge that a number of LSEs have some potential LLT resources under contract in some amounts as shown in the December 1, 2023 and June 1, 2024 confidential procurement data filings, these amounts, while encouraging, are so far not at sufficient levels of LLT resources to achieve our long-term climate goals in SB 100. Thus, the Commission is taking action here to

seek CPE procurement that will assist in making it possible for LSEs to procure the necessary LLT resources in the long run.

All LSEs are encouraged to take actions that will contribute to achieving the SB 100 goals, and smaller contracts can offer individual LSEs important portfolio development opportunities, as well as learning opportunities for LSEs in general. In addition, we note below that the quantities of resources procured by DWR will not be the full amount of resources needed in a particular category, which expressly leaves room for LSEs to procure some resources in smaller quantities for various unique reasons.

It is also important to acknowledge here that these resources do not represent the only pathway to achieving our SB 100 goals. We establish this procurement mechanism to enable these resources to compete with more mature technologies to serve as part of our SB 100 energy portfolio.

Thus, our next key criterion is to select resources that are unlikely to be procured by individual LSEs in significant enough amounts due to procurement challenges and market barriers such as risk, size, and cost. If a resource is already under contract in significant amounts and/or is a commercially-available technology, we do not intend to select it as an LLT resource to be procured by DWR as the CPE at this time.

In short, we are viewing the ability to ask DWR to procure resources as a CPE as a unique tool to be used strategically for a chiefly market transformation purpose, for technologies that are likely to be necessary and important to achieving SB 100 GHG reduction goals, but are not yet being procured in sufficient quantities by LSEs.

Turning to the specific resource types, we believe the categories included in the ALJ Ruling are the appropriate ones for current consideration, including:

OSW, OOS wind, geothermal, and LDES. However, in keeping with comments from several parties representing LDES and geothermal interests, those categories are appropriate to be further differentiated. In a similar fashion to how we have treated wind energy as three separate categories (OSW, OOS wind, and in-state wind), the LDES and geothermal categories are sufficiently diverse to justify sub-categories.

Within the geothermal category, there are numerous geothermal projects that have been developed in California and the West over the past several decades. Conventional geothermal is a fully-commercialized technology, though it may have a higher cost structure than some other resource types due to numerous factors, including its complexity and the need to develop a geothermal field as a fuel source ahead of smaller and more modular generation projects.

Enhanced geothermal systems (EGS) are an emerging technology identified by DOE[16] as needing a pathway to commercialization that will require significant capital investment. DOE defines EGS, as distinct from conventional geothermal, in the following manner:

> A naturally occurring geothermal system, known as a hydrothermal system, requires three key elements to generate electricity: heat, fluid, and permeability, which is when fluid can move freely through the underground rock.
>
> In many areas, however, the underground rock is hot but there is not enough natural permeability or fluids present. In those cases, an [EGS] can be used to create a human-made reservoir to tap that heat for energy.

[16] DOE has an initiative called the "Enhanced Geothermal Shot" that is designed to reduce the cost of EGS by 90% by 2035. *See* the following link: https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems#:~:text=The%20Enhanced%20Geothermal%20Shot%E2%84%A2%20is%20a%20department%2Dwide%20effort,geothermal%20heating%20and%20cooling%20solutions.

> In an EGS, fluid is injected deep underground under carefully controlled conditions to create new fractures and cause pre-existing fractures to re-open, creating permeability. Increased permeability allows fluid to circulate throughout the more fractured hot rock, and the fluid becomes hot as it circulates. Operators pump the hot water up to the surface, where it generates electricity for the grid.
>
> EGS could facilitate geothermal development beyond traditional hydrothermal regions, thereby extending geothermal energy production nationwide. EGS advances are being demonstrated worldwide today, in both the public and private sectors.

Unlike conventional geothermal, EGS has little to no air emissions and uses a closed circuit for the fluid underground. EGS can also access deeper and hotter thermal sources, making them easier to site in diverse locations throughout the country, including in California. Finally, like all forms of geothermal energy, EGS has a high capacity factor, but also more flexibility and dispatchability than conventional geothermal.

Due to the important distinctions between conventional and EGS, and the potential for EGS to be important in meeting the SB 100 goals, we will make a need determination for an amount of EGS, potentially to assist with the commercialization of EGS technology in California and worldwide.

While we make a need determination herein for EGS, we also note that there is an enormous amount of technical potential for geothermal energy in the United States, with a large proportion of it available in California.[17] A need determination for conventional geothermal is not necessary at this time, however, because the Commission has already ordered LSEs to procure 1 GW of clean, high-capacity-factor capacity in D.21-06-035. This procurement order is

[17] *See* DOE publication "Geovision: Harnessing the Heat Beneath Our Feet," May 2019 available at the following link: https://www.energy.gov/eere/geothermal/geovision

still outstanding, and LSEs are actively soliciting available qualifying resources. We expect a significant portion of this requirement to be met by conventional geothermal resources. Accordingly, asking a CPE to procure conventional geothermal at this time could interfere with LSE procurement. If procurement of conventional geothermal resources does not materialize in significant enough quantities to meet our long-term clean energy goals, we will consider requiring CPE procurement of conventional geothermal resources in subsequent need determinations associated with AB 1373 requirements.

Within the LDES category, so far most LDES has been procured by LSEs seeking storage with at least an 8-hour dispatch capability. This approach lends itself to procurement of lithium-ion batteries, because they are the cheapest and most modular form of storage, and can be stacked to meet the 8-hour-minimum long-duration requirements.

PSH is another conventional LDES technology that, similar to conventional geothermal, has been commercialized for decades but still may represent a higher-cost option compared to other resource options, particularly compared to lithium-ion batteries currently. While PSH may be more expensive because of the complex siting and infrastructure development required, it is still a well-established technology option.

In this category we agree with Form that as we increase the amount of intermittent resources on our electric grid, we will also increase the need for longer-durations of storage, including greater than 8-hour, as well as multi-day, storage. Our modeling of the LDES category has been necessarily limited by the information we have to rely on for commercially available technologies. Our primary capacity expansion model, RESOLVE, is not currently set up to capture all of the inter-day dynamics related to resources that can be available for long

periods of time, such as multi-day storage technologies. Our capacity expansion modeling analysis is based on a limited number of representative days, which can sometimes smooth away fluctuations in generation, load, and other factors that occur during real-world weather conditions. There is also sometimes imperfect information available regarding changing dynamics that affect this type of analysis, such as real-world weather conditions reflecting extreme temperatures, fuel shortages, renewable energy lulls, and reliability events. For these reasons, our capacity expansion modeling analysis using the RESOLVE model may not always identify the need for resources such as multi-day storage that could present value not yet captured in the modeling results.

There are several emerging and developing technologies that can meet a minimum need of 12-hour storage, as well as multi-day storage. More specific duration requirements may be addressed in the procurement request made to DWR within six months. These categories should be differentiated from both PSH and lithium-ion batteries, as uniquely useful to be pursued by a CPE to help develop the technologies and economies of scale necessary to make them widely available and commercially competitive.

Thus, we make a need determination for both 12-hour (or more) storage and multi-day storage, as long as they do not rely on already-commercialized lithium-ion batteries or PSH technologies.

In addition, a majority of parties appear to agree in comments that OSW is an obvious fit for CPE procurement. It represents a significant resource that, if developed, would bring numerous benefits to California, both energy and non-energy benefits (such as economic and port development), assuming it can be developed at reasonable cost. Though many LSE plans indicate interest in procuring OSW, it also has not been contracted in any significant way by LSEs to

date. Thus, asking a CPE to procure OSW would not interfere with LSE procurement. For all of these reasons, we make a need determination for procurement of an amount of OSW.

We note that we are not persuaded to select OOS wind for procurement by a CPE at this stage. OOS wind has already been successfully procured in reasonably significant amounts by LSEs. In addition, recent developments with subscription models for transmission access to OOS wind may help improve the ability of LSEs to procure additional amounts of OOS wind. Thus, we will not include a need determination for any OOS wind in this decision. We will watch the market for OOS wind and potentially consider the use of a CPE for OOS wind in the future.

In summary, as stated above in this section, the Commission finds a need for the centralized procurement of four different types of resources: 1) EGS; 2) 12-hour or more emerging LDES technologies, that are not lithium-ion or PSH; 3) emerging multi-day LDES technologies, that are not lithium-ion or PSH; and 4) OSW.

4.2. Need Determination

For clarity, we begin with an explicit definition of "need determination" in the context of AB 1373 determinations by this Commission. We will define "need determination" as follows: the maximum value determined by the Commission to be procured by a CPE for a given resource type and/or resource attribute(s), on behalf of all LSEs under the Commission's IRP purview.

The most recent PSP portfolio adopted in D.24-02-047 included the following resource need amounts (in nameplate) by 2035 that are relevant to the eligible resources already discussed above:

1. Geothermal: 2,000 MW;

2. Generic LDES: 500 MW;
3. 8-hour batteries: 2,800 MW;
4. PSH: 500 MW; and
5. OSW: 4,500 MW.

As most parties are aware and has been covered numerous times with respect to the assumptions used for RESOLVE capacity expansion modeling, in the LDES category certain technologies are used as proxies for the category as a whole, since the category contains a diverse set of technologies. Thus, for the purpose of making a need determination for DWR to solicit for, we will look at the total LDES in the portfolio, which is 3,800 MW by 2035.

In considering how much of each type of resource to determine is needed, for the geothermal and LDES categories, we determine that it is reasonable to make a need determination for roughly half of the quantities shown in the PSP portfolio to be procured using the CPE mechanism. Procuring up to this maximum amount will make a significant investment in the resource types identified, while still leaving significant volumes for LSEs to procure on their own, assuming the planned-for market transformation occurs and costs are reduced during or after the DWR procurement phase.

This means, we are making a need determination for up to 1,000 MW of EGS and up to 2,000 MW of emerging (non-lithium-ion and non-PSH) LDES (up to 1 GW of 12-hour+ duration and up to 1 GW of multi-day). As mentioned above, asking a CPE to procure the first half of these categories still leaves room for LSEs to procure more of these types of resources, should they so choose and/or if costs come down. It is also likely that future PSP portfolios may show the need for additional amounts.

We have considered the appropriate quantities of OSW in a somewhat different manner. First, as explained in D.24-02-047, the quantities of OSW in the PSP portfolio were selected to be consistent with the amount of OSW included in the portfolio sent to the CAISO for the prior year's (2023-2024) TPP base case. The amount of OSW represented in the individual LSE plans was less than 4,500 MW. At the other end of the spectrum, the full buildout of the current leaseholders from the U.S. Bureau of Ocean Energy Management (BOEM) auction for California call areas estimated by OSW developers is approximately 10,000 MW. And as cited by several parties in comments, the AB 525 Strategic Report includes 25,000 MW of OSW by 2045 as a goal. As with LDES and EGS, we want to leave room for LSEs to conduct individual procurement separate from DWR's initial tranche of investment. The CPE investment is likely to be at a scale that is too difficult for an individual LSE or group of LSEs to integrated into their plans because of size, timing, or development risk factors. We also do not want to create unnecessary market power by requesting that a CPE purchase the entirety of the capacity represented by the current leaseholders.

Looking at the cost-benefit analysis conducted by Commission staff, which considers the likelihood that benefits will exceed costs at particular levels of capacity procurement, the 7.6 GW scenario analyzed appears to be the level beyond which, based on current assumptions, it becomes more likely that the costs of procuring the OSW will exceed benefits in cost savings to electricity ratepayers. Beyond that level, net benefits currently appear to be lower, largely due to more expensive transmission upgrade costs and declining marginal benefits.

Our desire in the OSW category is to signal our strong interest in developing the resource and investing up front in order to achieve the economies

of scale that will be necessary eventually to realize the full benefits of the resource potential by around 2045. In addition, 7.6 GW represents the full physical cap for Morro Bay and Humboldt OSW resource buildout from a transmission perspective.

Finally, the 7.6 GW level of procurement achieves a good balance between the 4.5 GW in the most recent PSP portfolio and the maximum lease amounts available currently. For all the above reasons, we will adopt 7.6 GW as the maximum OSW need determination for DWR to seek to procure.

As already stated above, we emphasize that we will regularly evaluate the need for additional centralized procurement of these resources with each IRP cycle.

In summary, Table 1 below shows our total need determination quantities and categories.

Table 1. Need Determination Quantities

Resource Type	Quantity (Nameplate)
EGS	1 GW
LDES: 12-hour + duration	1 GW
LDES: Multi-day	1 GW
OSW	7.6 GW

4.3. Relationship to Load-Serving Entity Procurement

The ALJ Ruling proposed that an initial tranche of OSW be procured by DWR as a public good, with the purpose of investment in GHG reductions for California as a whole, specifically to attain the goal set forth in Section 454.53 (from SB 100). The same logic included in the ALJ Ruling for OSW is also

applicable to procurement of EGS and the two types of non-lithium-ion and non-PSH LDES identified in Section 4.1 above.

We note that we have targeted resources for procurement in Section 4.1 above that are intentionally different from resources already being procured by LSEs directly at sufficient volumes to result in market transformation, with the explicit intent not to interfere with LSE procurement and, in fact, to offer advantages to LSEs who may want to procure these types of resources in the future at more competitive prices.

The ALJ Ruling also proposed that any CPE procurement of resources would not count toward current procurement requirements of D.21-06-035, D.23-02-040, or D.24-02-047. Any CPE procurement would be kept separate from any LSE-specific requirements.

Here we note that all three of the above-referenced decisions relating to MTR procurement contain requirements for our IRP LSEs collectively to procure at least 2,000 MW of LLT resources with certain characteristics by no later than June 1, 2031. We agree that the resource procurement we are seeking from DWR through this decision should be treated separately from the MTR LLT procurement by LSEs. The MTR procurement is likely to involve established commercially-available technologies, whereas we are intentionally targeting emerging technologies with procurement by a CPE. In addition, the timing will be different, as described further below in Section 4.5. We will ask DWR to solicit for LDES and EGS resources with online dates after June 1, 2031; therefore, CPE procurement should not interfere with any LSE procurement to meet the MTR requirements.

The purposes of the LSE LLT procurement for MTR and CPE LLT procurement are distinct and complementary and therefore CPE procurement of

LLTs will not count toward any current requirements of D.21-06-035, D.23-02-040, or D.24-02-047.

The ALJ Ruling also proposed that any CPE procurement be kept separate from any LSE-specific requirements that may be included in the RCPPP, which has not yet been adopted, but is intended to replace the order-by-order procurement requirements used in IRP to date. The RCPPP is intended to cover both reliability- and GHG-driven procurement needs.[18]

We agree that it is logical to keep any CPE procurement as a result of this order separate and apart from any individual LSE requirements driven by the RCPPP, once adopted. Since LSEs will not have control over the timing or the amount of CPE procurement, it will be simpler for all actors if the CPE procurement is treated as a separate category, and not co-mingled with the LSEs' own procurement. In addition, we expect the RCPPP and its ultimate design not to have any bearing on CPE procurement requested in this decision.

The ALJ Ruling also proposed that LSEs not be allowed to opt out of CPE procurement once the Commission makes its need determination, as we are doing in this decision. Thus, all LSE customers would pay for the centralized procurement. Here we agree strongly with the ALJ Ruling's proposal for no individual LSEs being allowed to opt out. As noted several times already, we are selecting resources that are not being procured by LSEs currently in significant enough amounts to create market transformation. Thus, we are targeting resources, by definition, that are not competing in a significant way with LSE procurement currently. LSEs had the opportunity, in their November 1,

[18] For more information about consideration to date, *see* the September 8, 2022 ALJ ruling available at the following link: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat-ALL&DocID=496688637.

2022 individual IRP filings, and the subsequent semi-annual procurement data filings, to show their progress toward procurement of LLT resources and did not show that they are currently being procured by individual LSEs in significant enough amounts to achieve cost reductions.

Therefore, we are electing to ask DWR to attempt to procure resources as essentially a "downpayment" toward further future procurement by LSEs directly. Therefore, all LSEs will share equally in the risks (including timing, costs, and general development risks) and rewards (increment new clean energy resources that provide reliability, GHG benefits, and energy benefits) associated with collective action. Basic fairness dictates that the customers of all LSEs under our IRP purview should pay equally for this procurement. Once the Commission has sought DWR procurement after its review of procurement plans of LSEs under the Commission's IRP purview, as we are doing in this decision, AB 1373 does not provide for LSEs to opt out of costs for any centralized procurement once it is authorized to be undertaken.

Further, the Water Code additions[19] in AB 1373 require that the costs of DWR procurement of diverse LLT resources be paid for using a nonbypassable charge. This is consistent with the principle that all LSE customers should pay for the centralized procurement. Allowing LSEs to opt out after DWR has been asked by the Commission to undertake procurement on behalf of the LSEs would create an unworkable situation and thwart the statutory framework.

The ALJ Ruling also notes that POUs are permitted, by provisions in Water Code Sections 80820, 80822, and 80826, to voluntarily opt in to CPE procurement. This is a meaningful opportunity for POUs to help drive market transformation

[19] *See*, for example, Water Code Section 80821.

of emerging technologies and support California's clean energy and climate goals. The ALJ Ruling proposed that any provisions for these resources be handled directly between DWR and the POUs, without involvement of the Commission.

Here, we note that AB 1373 provides for a six-month period between the Commission making a need determination for centralized procurement and the Commission making a request to DWR to initiate procurement activities based on that need determination. It would be logical for any POUs wishing to join in the centralized procurement to make the election during this six-month period, so that DWR is able to plan for the total procurement requested and solicit for all of it at the same time, without advantaging or disadvantaging any group of LSEs or POUs in any individual solicitation.

We also note here our policy concern that POUs are not also required to invest in the resources that will be centrally procured under AB 1373. This investment should not be voluntary for the approximately 25 percent of customers in California who are served by POUs, because the investments are for the benefit of all Californians.

For at least the last 25 years, the lion's share of investments in resources that will help achieve the SB 100 goals, including investment in research, development and demonstration; renewables; energy storage; energy efficiency and demand response; and electric vehicle infrastructure; just to name a few, have been made by electricity customers who are under Commission jurisdiction and customers of IOUs and CCAs. It is inherently discriminatory and unfair not to require all electricity ratepayers in California to share equally in the investment for the good of all. In addition, it creates unnecessary and undesirable pressure on electricity rates for IOU distribution customers who are

already struggling with electricity affordability. We are hopeful that POUs will welcome the opportunity to contribute to the efforts to develop new clean energy resources with accompanying benefits.

4.4. Allocation of Costs and Benefits

The ALJ Ruling proposed that the costs and benefits of any centralized procurement be based on the IOU statewide allocation approach used by the Commission for the costs of retaining Diablo Canyon.[20] Namely, the costs of centrally procured resources would be allocated first to each IOU service area based on the IOU transmission access charge (TAC) area share of a 12-month coincident peak load, minus any non-benefitting POU load in that TAC area, and based on the share that occurred in the most recent full year that ended before the costs are allocated. Then, the ALJ Ruling proposed that the allocation to individual LSE customers within each IOU's territory could mirror the approach used in the CAM.[21] This would result in the application of nonbypassable charges to all LSE customers.

The ALJ Ruling proposed that the benefits of CPE procurement be allocated in the same manner as costs, basically mirroring CAM allocation of resource adequacy and GHG emissions reduction benefits. The benefits could also be used to inform the Power Source Disclosure Program that is overseen by the CEC.

For cost and benefit allocation methodology, the proposal in the ALJ Ruling is logical for the LDES resources, which are chiefly capacity resources. Thus, allocating to IOU service area, and then further differentiating by LSE,

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[20] *See* D.23-12-036, Sections 6-7.

[21] CAM was originally adopted in D.06-07-029.

annually on the basis of the 12-month forecast peak demand is consistent with the benefits delivered by the LDES resources, and is intended to be consistent with past CAM practice for consideration of CAM credit allocation. The difference in this instance is that the forecast will be a statewide forecast, and not by TAC area which is typically used for CAM credit allocations. Commission staff should use the most recent vintage of demand forecast for each year's allocation, including any future year forecasts of future allocations. We will adopt this approach for any of the LDES resources that DWR may procure. Consistent with past CAM practice, we expect the capacity costs to be charged to all customers, after netting any associated energy rents that might be associated with particular contract types.

The Commission also will not dictate the type of contract that DWR might enter into for LDES resources. It may be Resource Adequacy only or combined with energy deliveries. Historically, some CAM contracts have included energy dispatch rights and thereby provided energy revenues associated with the dispatch of the resources through the energy markets; the energy revenues were netted from the capacity cost prior to costs being charged to all customers.

We note that one reason the Commission required IOU procurement of LLT resources starting in 2004 was that large IOU-controlled resources were subject to cost-based bidding rules by the IOU procurement plans. The IOU CAM procurement contributed to a hybrid wholesale market where IOU-controlled resources bid into the market at cost to help mitigate the potential exercise of market power by wholesale generators. In today's market context, we observe that LSEs have entered into large volumes of capacity-only contracts to meet IRP requirements, and we have entered a new era where LSEs could be subject to high wholesale energy bidding behavior. We encourage DWR to

consider this history while considering the type of contracts to execute with resources that provide both capacity and energy benefits.

For EGS and OSW, we agree with the proposal by SCE in its comments that the resources that are energy-heavy would be more logically allocated on the basis of energy load share served among LSEs, rather than coincident peak demand. An advantage of this approach is that it can be done at the individual LSE level, without the need to allocate by IOU TAC area first. Thus, we will require that the costs and benefits of EGS and OSW be allocated annually based on a pro rata share derived from forecast loads. Commission staff should use the most recently available vintage of load forecast for each year's allocation, including any future year forecasts of future allocations.

Further implementation details to operationalize this policy may need to be addressed by the Commission in this proceeding prior to or during consideration of actual projects to be contracted by DWR.

4.5. Procurement Process and Timeline

The ALJ Ruling proposed a few key aspects of the procurement process to be undertaken by DWR:

1. All procurement should be conducted via a competitive solicitation process;
2. All proposed contracts should be submitted by DWR to the Commission for approval via an application, leading to a Commission decision on the contracts and their cost recovery; and
3. All contract volumes and pricing data can be submitted by DWR as confidential for a period of three years after approval (or rejection) by the Commission in a decision.

All parties support competitive solicitations for the purpose of procuring eligible LLT resources. This is also contemplated in the direction to DWR in the Water Code included in AB 1373. Thus, we will require competitive solicitations.

A number of parties recommended an advice letter process for Commission approval of any DWR contracts, rather than an application process. We are concerned that the advice letter process is too informal and will not allow for a full enough vetting of any proposed contracts. At the same time, we are undertaking this process with DWR as a partner, conducting procurement on behalf of the Commission and all LSEs under our IRP purview. It therefore seems inappropriate to ask DWR to submit an application as a supplicant before the Commission, since DWR is not a Commission-regulated entity.

Instead of either of these processes, we will model our approach on the way that the Wildfire Non-bypassable Charge emanating from AB 1054 (Stats. 2019, Ch. 79) is handled by the Commission and DWR. This process was established in D.19-10-056, and requires DWR to submit a memorandum to the Commission detailing the costs to be recovered from the participating IOUs via a nonbypassable charge; the ALJ then issues a ruling asking parties to comment on DWR's memorandum, and takes the additional steps necessary to render a Commission decision authorizing the cost recovery. The circumstances here are similar, where DWR is acting on behalf of ratepayers of all LSEs under our IRP purview. Therefore, instead of an application, we will ask DWR to submit a detailed memorandum summarizing all aspects of the process used in its solicitation, as well as the results and costs. The ALJ in this or a successor IRP proceeding will then issue a ruling establishing a separate phase of the proceeding and seeking party comment on the proposed contracts. Ultimately, this process will lead to a Commission decision approving or rejecting the

contracts, along with applying the adopted cost recovery mechanism. Consistent with direction in AB 1373, we expect this will be a nonbypassable charge on distribution customers.

On the confidentiality of DWR contracts and prices, we will generally follow existing and already-established rules for how confidentiality of procurement contracts is handled, as established in D.06-06-066 and its successor decisions. However, as proposed by numerous parties in comments, we will also recommend to DWR that they consider soliciting open-book bids for provision of some resources. Using open-book bidding, proposed contracts contain placeholder values, and the actual costs of the contract may be permitted to go up or down, depending on the actual costs incurred. We do not require this approach, partly because this option may necessitate a different approach to confidentiality, since the contracts would allow DWR to pay developers based on actual costs, which would be revealed to DWR and the Commission, but still remain otherwise confidential. Thus, those types of contracts may need to remain confidential for much longer than other types. For these types of open-book contracts, we will refrain from making any detailed rules about confidentiality in this decision, and instead will address this in the context of individual contracts presented to us for consideration by DWR in the future.

Water Code Section 80820 also requires that the Commission and DWR establish a "procurement group" to advise DWR on any procurement undertaken. The ALJ Ruling suggested that this group be convened by and advisory to DWR and consist of non-market-participants, as well as agency staff. The ALJ Ruling also proposed that DWR be encouraged to retain an expert consultant to advise on the procurement as an independent evaluator and/or support for DWR staff procurement determinations.

No party objected to the idea that DWR retain an expert consultant; this approach has worked well for IOU procurement, and therefore we will recommend this approach to DWR. It may provide assistance both in the preparation of the solicitation, as well as in evaluating bids.

As far as the composition of the procurement group, numerous parties suggested it be modeled on the PRG structure used by the IOUs. Several LSEs also argued in comments that LSE representatives should be allowed to serve on the procurement group, since they (and their customers) have a vested interest in the outcome of DWR's solicitations. LSE representatives who are directly involved in conducting solicitations for LSEs should not also serve on the procurement group as advisory to DWR. However, we are persuaded that LSEs should have representation on the procurement group, both because they may have expertise to bring to the table and because their ratepayers will ultimately be paying the costs of DWR's contracts. Thus, we will ask that DWR include at least one representative of a community choice aggregator (CCA) organization, at least one representative of an electric service provider (ESP) organization, and at least one representative of an IOU who is not otherwise involved in assisting DWR with solicitation activities. Though we do not specify the inclusion of POUs, we observe that if a POU has requested procurement by DWR, it may also be logical to include a POU representative on the procurement group.

In addition, a number of parties recommend that DWR be encouraged to conduct outreach to and allow representation on the procurement group from community groups and Tribal Nations with vested interests in the procurement. We agree, and encourage DWR to use the input from these groups as much as possible.

When DWR submits its memo to the Commission detailing its solicitation activities and results, we will ask that DWR identify the individuals involved in the solicitation process, either in a direct advisory capacity and/or as procurement group participants during the solicitation, and we will require that DWR not allow individuals to participate in the solicitation process if they have participated in the procurement group (and vice versa) during the course of a single solicitation.

The ALJ Ruling also included an outline of a proposed schedule for DWR to prepare and issue a solicitation. Generally, preparatory activities were suggested for 2025-2027, pre-bid activities in 2026-2027, with solicitations open for bid between 2026 and 2028, bid evaluation in 2027-2028, and contracts submitted to the Commission in 2027-2028.

A number of parties commented that this schedule outline was somewhat too slow to attract enough interest from developers. At the same time, we are cognizant of the fact that DWR will need time to put together its team to handle the solicitations and all of the tasks leading up to them. Thus, the schedule we put forward below provides a general framework, but we expect adjustments will need to be made as this effort progresses. We also expect that DWR itself will want to present at least some aspects of its plans to stakeholders to receive feedback prior to launching any solicitations. We will defer to DWR's judgment on the best way to do this, but note that because of the groundbreaking nature of this procurement, it may be preferable to err on the side of transparency and inclusiveness in terms of allowing ample stakeholder feedback on DWR's approach.

In terms of the schedule for solicitations, we also note that the volume of resources contained in the need determination in this decision is large. Therefore,

it will likely be prudent for DWR not to conduct a single solicitation for the full amount. Instead, we recommend below a schedule of solicitations designed both to take advantage of learning by starting small, as well as the fact that some projects may not yet be ready to participate in a first solicitation, but could be ready by a subsequent solicitation round.

We also expect that DWR will need all of 2025 for preparatory activities for solicitations, such that 2026 is the first realistic year that solicitations could begin. With that in mind, we adopt the following solicitation schedule as a framework to organize the process. Timing reality may deviate from these plans somewhat, but our staff will work closely with DWR to execute this plan.

Table 2.
Recommended Approach and Indicative Timing for LLT Solicitations

Activity	**Timing Target**
DWR preparatory activities, including formation of procurement group	Late 2024 and 2025
DWR development of solicitation plans and materials, in consultation with Commission staff and procurement group	2025
First LDES Solicitation – Up to 1 GW of multi-day storage and up to 1 GW of 12+-hour duration storage, for deliveries beginning June 1, 2031 through June 1, 2035	
Pre-bid activities	Early 2026
Solicitation open for proposals	Late 2026
Proposed contracts submitted to Commission for approval	Mid 2027

Activity	**Timing Target**
First Enhanced Geothermal Solicitation – Up to 1 GW for deliveries beginning June 1, 2031 through June 1, 2035	
Pre-bid activities	Late 2026
Solicitation open for proposals	Early 2027
Proposed contracts submitted to Commission for approval	Late 2027
First OSW Solicitation – Up to 7.6 GW, for deliveries by June 1, 2035	
Pre-bid activities	Early 2027
Solicitation open for proposals	Late 2027
Proposed contracts submitted to Commission for approval	Mid 2028
Second LDES Solicitation – Residual amount not procured in first LDES solicitation, of up to 1 GW of multi-day storage and up to 1 GW of 12+-hour duration storage, for deliveries beginning June 1, 2033 through June 1, 2037	
Pre-bid activities	Early 2028
Solicitation open for proposals	Late 2028
Proposed contracts submitted to Commission for approval	Mid 2029
Second Enhanced Geothermal Solicitation – Residual amount not procured in first EGS solicitation, of up to 1 GW, for deliveries beginning June 1, 2033 through June 1, 2037	
Pre-bid activities	Late 2028
Solicitation open for proposals	Early 2029
Proposed contracts submitted to Commission for approval	Late 2029

Activity	**Timing Target**
Second OSW Solicitation – Residual amount not procured in first OSW solicitation, of Up to 7.6 GW, for deliveries by June 1, 2036	
Pre-bid activities	Early 2029
Solicitation open for proposals	Late 2029
Proposed contracts submitted to Commission for approval	Mid 2030
Third OSW Solicitation – Residual amount not procured in first and second OSW solicitations, of Up to 7.6 GW, for deliveries by June 1, 2037	
Pre-bid activities	Late 2029
Solicitation open for proposals	Early 2030
Proposed contracts submitted to Commission for approval	Late 2030

We note that the quantities in each solicitation listed above may be adjusted downward in the second and third rounds, depending on the amount of contracting actually approved at the conclusion of the prior solicitation rounds.

We also recognize that the above table represents a plan that will likely change. Thus, we request that DWR send periodic or interim updates on progress and changes to solicitation schedules to the Executive Director of the Commission, with a copy to the relevant IRP service list and Energy Division (at EnergyDivisionCentralFiles@cpuc.ca.gov). DWR should update the Commission at least annually, or more frequently after major milestones or with schedule changes, in advance of submitting a formal Memorandum to the Commission detailing procurement results.

5. Next Steps

We note that AB 1373 gives the Commission six months after the initial September 1, 2024 need determination deadline to make a procurement request to DWR to initiate the necessary procurement. We will define a "procurement request" as follows: after a need determination is made by the Commission, the Commission will send a procurement request to the CPE triggering the initiation of the procurement process.

We expect that procurement request to be informal, likely in the form of a letter from the President of the Commission asking that DWR formally initiate procurement activities. The Commission may, at this point, add additional clarification or details regarding recommendations to the solicitation process at that time, consistent with the framework in this decision. And as already stated above, we intend to work closely with DWR throughout the solicitation process, at the staff and leadership levels.

Finally, after each solicitation round is completed, the Commission may choose to revise or send a subsequent procurement request, reflecting the results of contracting from the prior round.

6. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

One public comment was submitted by EPIC, an organization which also submitted formal reply comments in response to the ALJ Ruling. EPIC's public

comment echoes its formal reply comments. No other public comments were submitted.

7. Comments on Proposed Decision

The proposed decision of ALJ Julie A. Fitch in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

8. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Julie A. Fitch is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. An optimal electricity portfolio, as adopted by the Commission as part of each PSP, is a product of a series of changing factors, including cost assumptions, available technologies, and GHG emissions reduction goals.
2. The resource types considered for a need determination for centralized procurement are geothermal, LDES, OOS wind, and OSW.
3. Geothermal electricity, OOS wind, lithium-ion battery LDES, and PSH are a commercialized technologies.
4. EGS is an emerging technology distinct from conventional geothermal, and is the subject of an initiative at DOE called "Enhanced Geothermal Shot" designed to reduce the costs of EGS.
5. 12+-hour LDES and multi-day LDES are emerging technologies that are not yet sufficiently available with known costs to be modeled in previous PSP portfolios adopted by the Commission. Therefore, proxies have been used.

6. OSW is an emerging technology with very few deployments worldwide in deep-water locations such as the California coast.

7. As of this decision, numerous LSEs have OOS wind projects under contract. Some also have conventional geothermal, EGS, and 8+hour LDES projects under contract.

8. As of this decision, almost no LSEs have EGS, 12+-hour LDES, multi-day LDES, or OSW projects under contract. Those LSEs that do have these types of projects do not have any significant volumes under contract relative to the size of the resource potential or in enough quantities to spur market transformation.

9. The PSP portfolio adopted in D.24-02-047 included the need for nameplate capacities of 2,000 MW of geothermal; 3,800 MW of LDES; and 4,500 MW of OSW, by 2035.

10. OSW developers state that current BOEM leaseholders for OSW projects have a potential capacity of approximately 10,000 MW.

11. Asking a CPE to procure all OSW BOEM leaseholder capacity has the potential to result in the exercise of market power.

12. The November 1, 2022 individual LSE IRP filings represented the CCAs' opportunity to offer proposals under Section 454.51(d) requirements.

13. The November 1, 2022 individual LSE IRP filings, along with their August 1, 2023 and December 1, 2023 procurement data filings, do not show LLT resources under contract to LSEs in sufficient quantities to achieve scale and cost reductions in the long run.

14. POUs are permitted by AB 1373 Water Code Sections 80820, 80822, and 80826 to opt in voluntarily to DWR centralized procurement.

15. DWR is acting in the public interest and as a partner to the Commission and its LSEs in soliciting and contracting for LLT resources on behalf of all customers under the Commission's IRP purview.

16. D.06-06-066, and several decisions augmenting it, cover generally-applicable confidentiality rules for contracts submitted before the Commission.

Conclusions of Law

1. AB 1373 authorizes the Commission to request that DWR conduct centralized procurement of certain eligible LLT resources, on behalf of customers of all LSEs under the Commission's IRP purview.

2. By September 1, 2024, the Commission is required to make an initial need determination for centralized procurement by DWR.

3. A need determination, for purposes of AB 1373 should be defined as follows: the maximum value determined by the Commission to be procured by a CPE for a given resource type and/or resource attribute(s), on behalf of all LSEs under the Commission's IRP purview.

4. For purposes of AB 1373, a "procurement request" should be defined as follows: after a need determination is made by the Commission, the Commission will send a procurement request to the CPE triggering the initiation of the procurement process.

5. If a need for LLT resources is found by the Commission, within six months after September 1, 2024, the Commission may make a request to DWR to exercise the centralized procurement mechanism outlined in AB 1373.

6. To make a need determination for the exercise of centralized procurement, AB 1373 codified as Section 454.52(a)(4), directs that the Commission "determine if there is a need for the procurement of eligible energy resources based on a review of the integrated resource plans submitted by load-serving entities in

compliance with the requirements of this section and Section 454.53 and the progress towards meeting the portfolio of resources identified pursuant to subdivision (1) of Section 454.51."

7. The Commission should reevaluate the need for centralized procurement of LLT resources in each IRP cycle, when considering the adoption of a PSP portfolio.

8. The need determinations made by the Commission for centralized procurement should be maximum amounts; DWR should be authorized to procure any amount from zero up to the maximum need determination, depending on the costs, value, and other factors of the bids received.

9. Resource diversity should be an explicit and important criterion for the selection of resources to be centrally procured.

10. Resources that are important to reducing the overall emissions in the electricity sector, but which may not compete favorably in price against other resources, should be considered for centralized procurement.

11. Market transformation of emerging technologies important to achieving GHG emissions goals in Section 454.53 should be an important purpose for selection of resources to be centrally procured.

12. DWR, at this time, should not be requested to conduct centralized procurement for technologies that are already widely commercially available.

13. Technologies that utilize fossil fuels to generate electricity are not eligible for centralized procurement by DWR according to Section 454.52(h)(1)(D).

14. The Commission should not, at this time, ask DWR to solicit for resource types that are already being widely procured in significant volumes by numerous individual LSEs.

15. EGS should be defined based on the U.S. DOE definition in its "Enhanced Geothermal Shot" initiative.

16. LDES requested for DWR to solicit for centralized procurement should include 12+-hour LDES and multi-day LDES, but not lithium-ion batteries or PSH.

17. It is reasonable to ask DWR to solicit approximately half of the resource need identified in the most recent adopted PSP portfolio in D.24-02-047 for LDES and geothermal, in order to facilitate a downpayment on technologies necessary to achieve SB 100 goals, while still leaving room for LSEs to procure the technologies individually, after costs are reduced and market transformation is underway.

18. It is reasonable to ask DWR to solicit for 7.6 GW nameplate of OSW, which signals a strong interest in developing the resource, represents the level beyond which our staff cost-benefit analysis shows the potential for higher risks to ratepayers, is sufficient to foster cost savings as the resource is developed at scale, and avoids the potential for market power issues.

19. Centralized procurement of LLT resources should be considered by the Commission in a separate category from individual LSE procurement.

20. Any CPE procurement should not count toward the requirements of D.21-06-035, D.23-02-040, or D.24-02-047.

21. The Commission should evaluate in subsequent AB 1373 need determinations the LSE progress toward the D.21-06-035 requirements for procurement of 1 GW of high-capacity-factor clean LLT resources and consider whether additional CPE procurement of conventional geothermal resources is necessary.

22. CPE procurement should be kept in a separate category for purposes of consideration of an RCPPP in the future in this proceeding.

23. AB 1373 does not provide an opportunity for LSEs to opt out of centralized procurement, once the Commission has made its need determination. LSEs subject to the Commission's IRP purview should not be allowed to opt out of paying for their share of centralized procurement.

24. All benefiting LSE customers, under the provisions of Water Code Section 80821, will be subject to a nonbypassable charge, as determined by the Commission when any contracts are approved.

25. The burden of the investment costs for LLTs should not fall solely on the customers of LSEs under the Commission's jurisdiction.

26. Costs and benefits of centralized procurement should be allocated annually by forecast energy load share for any energy-producing resources, including EGS and OSW.

27. Costs and benefits of centralized procurement should be allocated annually by forecast 12-month peak demand in each TAC area, and then further allocated to LSEs in the same manner as CAM resources, for any LDES capacity.

28. Further operational and implementation details of the allocation of costs and benefits of CPE procurement to LSEs will be handled in this proceeding or its successor before or during consideration of actual contracts to be signed by DWR.

29. It is not appropriate for DWR, as a partner agency, to file either an advice letter or an application before this Commission.

30. The consideration of any contracts recommended by DWR for execution should be brought to the Commission via a memorandum submitted by DWR in this proceeding or its successor and served on the service list.

31. Subsequent to DWR's memorandum, the assigned ALJ should initiate a separate phase of this proceeding or its successor to consider DWR's recommended contracts for Commission approval, as well as their cost recovery.

32. Confidentiality provisions for any DWR contracts or potential contracts should follow generally established confidentiality rules emanating from D.06-06-066.

33. The Commission should recommend that DWR allow an option for bidders in each solicitation to provide open-book contract proposals.

34. Water Code Section 80820 requires that the Commission and DWR establish a procurement group to advise DWR on the solicitation process and results.

35. The Commission should recommend that DWR retain an expert consultant to advise on all aspects of the solicitation process and its results.

36. Representatives of LSEs should be allowed to participate as members of the procurement group as long as they are not directly involved in conducting solicitations for an LSE.

37. DWR should solicit procurement group members from affected community groups and Tribal Nations.

38. DWR should conduct a series of solicitations designed to contract for the resources determined to be needed in this decision, in a manner similar to the outline in Table 2 of this decision. DWR should keep the Commission and staff informed about the progress of solicitations and major milestones, via updates to the Executive Director, Energy Division, and the service list of this or a successor IRP rulemaking.

39. Commission staff should work closely with DWR on the preparation for and conduct of the resource solicitations recommended in this decision.

40. The Commission should not need to render a second formal decision during the six-month window after September 1, 2024, and after any subsequent need determination in future IRP cycles. The request for procurement after the Commission's formal need determination in a decision may come in the form of a letter to DWR from the Commission president and/or the assigned Commissioner to the IRP rulemaking, consistent with the provisions of this decision.

41. This proceeding should remain open.

O R D E R

IT IS ORDERED that:

1. The Commission has evaluated eligible resource types under Public Utilities Code Section 454.52(h)(1)-(2) categories and has determined that there is a need for centralized procurement through competitive solicitations by the Department of Water Resources (DWR) as a Central Procurement Entity for the following resources, in nameplate capacity, with energy deliveries and/or capacity online between June 1, 2031 and June 1, 2037. DWR is not required to procure all of the below resources and may procure as little as zero, depending on the reasonableness of prices offered by developers:

   (a) A maximum of 1,000 megawatts (MW) of Enhanced Geothermal Systems, as defined by the United States Department of Energy's "Enhanced Geothermal Shot" initiative;

   (b) A maximum of 1,000 MW of long-duration energy storage (LDES) that can discharge for 12 hours or more that does not employ lithium-ion batteries or pumped storage hydroelectric (PSH) technologies;

   (c) A maximum of 1,000 MW of multi-day LDES that does not employ lithium-ion batteries or PSH technologies; and

(d) A maximum of 7,600 MW of offshore wind.

2. The Commission recommends that the Department of Water Resources (DWR) undertake a series of solicitations for the resources identified in Ordering Paragraph 1 above, in a manner similar to that outlined in Table 2 of this decision. The Commission requests that DWR keep the Commission's Executive Director, Energy Division, and the service list for this or a successor integrated resource planning rulemaking informed as to solicitation progress and major milestones.

3. All load-serving entities with obligations under the integrated resource planning process of the Commission related to Public Utilities Code Sections 454.51 and 454.52 shall be required to pay for their proportional share of any resources determined to be needed by the Commission and centrally procured by the Department of Water Resources for the life of the contracts, once approved by the Commission.

4. The costs and benefits of any procurement of offshore wind and enhanced geothermal systems shall be allocated annually on the basis of forecast energy load share, for the life of each contract.

5. The costs and benefits of any procurement of long-duration energy storage shall be allocated annually to each transmission access charge area based on forecast 12-month peak load, and then further allocated to each load-serving entity's customers in the same manner as the Cost Allocation Mechanism adopted in Decision 06-07-029, for the life of each contract.

6. The Commission recommends that the Department of Water Resources seek commitments from any publicly-owned utilities that seek to opt in voluntarily to the centralized procurement of resources during the six-month period after the Commission makes its resource need determination.

7. The Commission recommends that the Department of Water Resources retain an expert consultant to advise on all aspects of the design, conduct, and outcome of the competitive solicitations for long lead-time resources.

8. Representatives of load-serving entities (LSEs) shall be allowed to participate as members of the procurement group established in response to Water Code Section 80820 as long as they are not directly involved in conducting solicitations for an LSE.

9. The Commission recommends that the Department of Water Resources conduct outreach to and invite representatives from community groups and Tribal Nations affected by the resource developments contemplated in the competitive solicitations to serve on the procurement group referred established according to Water Code Section 80820.

10. The Department of Water Resources shall submit its recommended contracts to the Commission in the form of a memorandum (with confidential version as necessary) sent to the Commission and served on the service list for this proceeding or its successor.

11. Rulemaking 20-05-003 remains open.

This order is effective today.

Dated _____, at San Francisco, California

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 79-E

Tier Designation: 2

Subject of AL: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing): COMPLIANCE

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-05-065, E-4999, E-5125,

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 8/8/24

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Amulya Yerrapotu
Title: Policy Analyst
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: (925) 378-6729
Facsimile (xxx) xxx-xxxx:
Email: ayerrapotu@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

July 8, 2024

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Supplemental Advice Letter 79-E-A

RE: Supplemental: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

PURPOSE

MCE hereby submits this supplement to Advice Letter 79-E addressing corrections to the 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program that was submitted on July 5, 2024.

This supplemental advice letter is made in accordance with General Order (GO) 96-B and General Rule 7.5.1, which authorizes utilities to make revisions or corrections to advice letters through the submittal of a supplement. This supplement replaces Advice Letter 79-E in part, and Attachment A of Advice Letter 79-E in its entirety.

BACKGROUND

Pursuant to Ordering Paragraphs ("OP") 2 and 4 of Resolution E-4999,[1] OP 3 of Resolution E-5125,[2] and OPs 2 and 3 of D.24-05-065,[3] Marin Clean Energy ("MCE") submitted MCE AL-79, the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT) program for the program year ("PY") 2025, on July 5, 2024.

On page 4 of Attachment A, in Table 1: MCE Budget Forecast for PY 2025, MCE inadvertently

[1] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. MCE's implementation Advice Letter, MCE AL 42-E/E-A/E-B was approved in Resolution E-5124, which brought MCE under the same program rules and reporting structure applicable to the IOUs.
[2] OP 3 of Resolution E-5125 directed that DAC-GT and CS-GT Annual Budget Advice Letters are to be submitted as Tier 2 ALs to allow for additional review and oversight.
[3] OP 2 of D.24-05-065 discontinues the CS-GT program and directs program administrators to transfer remaining capacity, customers, and programs into the DAC-GT program. OP 3 of D.24-05-065 makes several modifications to the DAC-GT program, which are reflected in this budget submission.

used an incorrect value for the Generation Cost Delta, incorrectly inflating energy consumption from program participants by 25%. This, in turn, impacts subsequent sums (Total DAC-GT PY 2025 Budget Forecast, Total DAC-GT Budget Request for PY 2025, and Total MCE Budget Request for PY 2025).

After correcting the error, the 2025 Generation Cost Delta, Total DAC-GT PY 2025 Budget Forecast, Total DAC-GT Budget Request for PY 2025, and Total MCE Budget Request are all reduced by $489,242.61. MCE now requests a total budget of $6,302,724 for PY 2025.

MCE is submitting a revised Attachment A to correct the error. Please discard the previously submitted Attachment A in its entirety.

PROPOSED MODIFICATIONS TO ADVICE LETTER 79-E

MCE proposes the following modification to Advice Letter 79-E, as shown in bold font.

"MCE hereby submits the budget request for PY 2025 for the DAC-GT program. Per Resolution E-4999, the budget request includes both the budget reconciliation for the previous PY (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). Because D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a project for the CS-GT program, MCE does not include CS-GT in the PY 2025 budget forecast. However, MCE continues to include CS-GT program costs in the PY 2023 budget reconciliation. In summary, MCE requests a total budget of **$6,302,724** for the DAC-GT program for PY 2025, including PY 2023 CS-GT reconciliation costs. Additional details can be found in Appendix A."

TIER DESIGNATION

This supplemental AL is submitted with a Tier 2 designation, the same Tier designation pursuant to OP 3 of Resolution E-5125.

EFFECTIVE DATE

MCE requests that this supplemental AL become effective concurrent with the original AL 79-E, 30 calendar days from the July 5, 2024 date filing.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002 and Application A.22-05-022.

For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

MCE requests that the Commission, pursuant to General Order 96-B, General Rule 7.5.1, maintain the original protest and comment period designated in advice letter 79-E. Protests must be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter shall be sent electronically to the attention of:

Amulya Yerrapotu
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: ayerrapotu@mceclean energy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Amulya Yerrapotu at (925) 378-6729 or by electronic mail at ayerrapotu@mceclean energy.org.

/s/ Amulya Yerrapotu

Amulya Yerrapotu
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Appendices

Appendix A: PY 2025 Budget Request
Appendix B: PY 2025 ME&O Plan

cc: Service List for R.14-07-002 and A.22-05-022

Budget Forecast for the Disadvantaged Communities Green Tariff Program for Program Year 2025

Proposed by Marin Clean Energy

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1. BACKGROUND

MCE is a program administrator (PA) of the Disadvantaged Communities (DAC) Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs. Per Resolution E-4999, annual program budgets must be presented by program and include the following budget line items:[1]

1. Generation cost delta, if any;[2]
2. 20 percent bill discount for participating customers;
3. Program administration costs: [3]
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance;
    e. Procurement;
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only).

In this program budget, MCE includes both the budget reconciliation for the previous program year (PY) (i.e., PY 2023) and the budget forecast for the upcoming PY (i.e., PY 2025). As D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a CS-GT project, MCE does not include CS-GT program costs for PY 2025, and only includes CS-GT costs in the budget reconciliation for PY 2023, but does not include CS-GT program costs for PY 2025.

In addition to budget reconciliation and forecast, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on:

1. Existing solar generation capacity at previous PY's close (i.e., December 31, 2023);
2. Forecasted solar generation capacity under contract for procurement in the upcoming PY;
3. Customers served at previous PY's close (i.e., December 31, 2023); and

---

[1] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to MCE Advice Letter 42-E filed on May 7, 2020.

[2] Resolution E-4999 establishes that *above market* generation 9costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate."

[3] Resolution E-5124 established that PG&E can charge "CCA Integration Costs" to the programs; i.e. costs that incur to PG&E to enable CCAs to administer the programs (e.g., billing support functions). To date, CCAs have been including CCA integration costs on their budget ALs. On March 2, 2023, PG&E submitted Advice Letter 6872-E requesting that the CPUC approve a tariff modification to allow PG&E to record these CCA integration costs directly to PG&E's subaccount, instead of the CCAs seeking cost recovery. Therefore, MCE does not include the CCA integration cost in its 2025 budget forecast. However, MCE still includes the CCA integration cost in the calculation of its administration cost cap, per Resolution E-5124.

4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission's (CPUC or Commission) Energy Division staff directly:

1. Calculation of the generation cost delta;
2. Calculation of the 20% bill discount to participating customers.

2. BUDGET FORECAST FOR PY 2025

For PY 2025, MCE forecasts a total budget of $5,456,986 for the DAC-GT program. This budget forecast accounts for the program modifications established in D.24-05-065, including discontinuing the CS-GT program and rolling unused capacity into the DAC-GT program, increasing DAC-GT program capacity, and removing the Green-e certification requirement. A detailed budget forecast for each program by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PY 2025

Category	DAC-GT
Generation Cost Delta	$ 1,956,970
20% Bill Discount	$ 3,310,666
Program Administration	
Program Management	$ 22,820
Information Technology	$ 11,617
Billing Operations	$ 98,868
Regulatory Compliance	$ 18,996
Procurement	$ 15,690
Subtotal Program Administration	**$ 167,991**
Marketing, Education & Outreach	
Labor Costs	$ 6,357
Outreach and Material Costs	$ 15,000
Subtotal ME&O	**$ 21,357**
Total	**$ 5,456,985**

MCE provides a brief description of each of the budget line items below.

Generation Cost Delta
To date, MCE has been using interim solar generation resources to support the DAC-GT program while it is procuring a dedicated solar facility for the program. On June 20, 2022, the Commission

granted MCE's request to approve its dedicated DAC-GT power purchase agreement (PPA).[4] On November 11, 2024, the Commission approved MCE's first request to amend its dedicated DAC-GT PPA. On June 19, 2024, the Commission approved MCE's second request to amend its dedicated DAC-GT PPA. The new dedicated solar generation facility is expected to come online in early 2026. As such, the DAC-GT generation cost delta budget forecast for 2025 is based on the PPA price of the current interim solar generation resource, compared to the costs of serving customers under MCE's residential base tariff, the "Light Green" tariff.

Decision 24-05-065 approves a 50% expansion of MCE's DAC-GT program capacity. Decision 24-05-065 also rolls any unused CS-GT capacity into MCE's DAC-GT program. MCE's DAC-GT program now has a total capacity of 8.249 MW. MCE plans to enroll customers using an interim resource as it works to procure a resource to serve the remaining program capacity. MCE anticipates using the existing DAC-GT interim resource for this purpose.

20 Percent Bill Discount

As set forth in Resolution E-5124, MCE calculates the 20% bill discount on both the generation and transmission and distribution (T&D) portion of the electric bill for participating customers. The bill discount is then fully included on the generation portion of customer bills, i.e., the discount reduces the electric generation costs of a customer's bill only.[5] MCE then recovers these program costs via this budget AL filing.

In PY 2025, MCE expects to have approximately 5,805 customers enrolled in the DAC-GT program. D.24-05-065 expands MCE's DAC-GT program capacity by 3.609 MW. MCE estimates that it will be able to serve 2,540 customers with this new capacity, in addition to the existing 3,265 customers currently served by existing program capacity. MCE plans to enroll customers using an interim resource as it works to procure a new resource to serve the remaining program capacity. The PY 2025 forecast for the 20 percent bill discount is based on the actual average monthly bill discount provided to participating customers in 2023, with a 25% increase to account for forecasted increases in electricity rates. Future customers enrolled under the expanded capacity are assumed to have the same usage as existing customers.

Program Administration Costs

Program administration includes program development, management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations cover costs for ongoing billing operations and customer support, including the costs of MCE's third-party billing provider. While D.24-05-065 directs PG&E to provide a cost estimate for implementing an automated billing solution, it is uncertain whether such a solution will be implemented. As such, for the time being, MCE assumes that billing costs will remain as they are now. Regulatory Compliance covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, ongoing contract management, as well as annual renewable energy credit (REC) retirement and compliance functions. D.24-05-065 removes the Green-e certification requirement, instead ordering program

[4] See Disposition of MCE AL 63-E, MCE Disadvantaged Communities Green Tariff Program 2022 Power Purchase Agreement Approval.

[5] Resolution E-5124, p. 12.

administrators to independently track the retirement of RECs. MCE estimates those costs in the procurement forecast.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in two categories – (1) MCE labor costs; and (2) MCE direct costs for outreach and material.

3. BUDGET CAPS

Resolution E-4999 establishes a cap of 10% of the total budget for program administration costs and a cap of 4% of the total budget for ME&O costs, to apply beginning with each administrator's third program year.[6] Subsequently, in recognition that these programs may exceed the established caps because of their relatively small size, the time it takes to launch, and other factors, the Commission permitted PAs whose budgets exceed the established caps to submit a rationale supporting the exceedance in their Annual Budget Advice Letters (ABAL).[7] The ABAL was elevated from Tier 1 to Tier 2 to allow for additional review of this and other ABAL components.[8]

The 2025 budget forecast summarized above in Table 1 results in DAC-GT program administration budgets of 3% and ME&O budgets of 0%. As such, MCE does not require an adjustment to the program administration budget cap for DAC-GT for PY 2025.

4. BUDGET RECONCILIATION FOR PY 2023

MCE submitted a budget forecast for PY 2023 as a part of its 2023 Budget Request and Marketing, Education, and Outreach Plan in AL 58-E on February 1, 2022. The table below shows the forecasted and actual costs for PY 2023 per budget line item, as well as the true-up amount that will be carried forward to future program years.

[6] Resolution E-4999, p. 27.
[7] Resolution E-5125, p. 7.
[8] *Id.*

Table 2: MCE Budget Reconciliation for PY 2023

Category	DAC-GT			CS-GT		
	Forecast	Actual	**True-up (Actual - Forecast)**	Forecast	Actual	**True-up (Actual - Forecast)**
Generation Cost Delta	$ 988,083	$ 994,287	**$ 6,204**	$ -	$ -	**$ -**
20% Bill Discount	$ 280,035	$ 1,489,780	**$ 1,209,745**	$ -	$ -	**$ -**
Program Administration						
Program Management	$ 84,050	$ 10,125	**$ (73,925)**	$ 97,150	$ 3,062	**$ (94,088)**
Information Technology	$ 30,537	$ 7,343	**$ (23,194)**	$ 19,009	$ 1,531	**$ (17,478)**
Billing Operations	$ 76,735	$ 89,913	**$ 13,178**	$ 34,422	$ 1,531	**$ (32,891)**
Regulatory Compliance	$ 7,860	$ 27,582	**$ 19,722**	$ 7,860	$ 18,510	**$ 10,650**
Procurement	$ 26,815	$ 25,189	**$ (1,626)**	$ 31,093	$ 1,834	**$ (29,259)**
CCA Integration Costs	$ 2,430	$ 1,623	**$ (807)**	$ -	$ -	**$ -**
Subtotal Program Administration	**$ 228,427**	**$ 161,775**	**$ (66,652)**	**$ 189,534**	**$ 26,468**	**$ (163,066)**
Marketing, Education & Outreach						
Labor Costs	$ 21,615	$ 3,220	**$ (18,395)**	$ 59,605	$ 2,260	**$ (57,345)**
Outreach and Material Costs	$ 20,000	$ 6,248	**$ (13,752)**	$ 26,000	$ -	**$ (26,000)**
Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 25,000	$ -	**$ (25,000)**
Subtotal ME&O	**$ 41,615**	**$ 9,469**	**$ (32,146)**	**$ 110,605**	**$ 2,260**	**$ (108,345)**
Total	**$ 1,538,160**	**$ 2,655,310**	**$ 1,117,150**	**$ 300,139**	**$ 28,728**	**$ (271,411)**

5. 2025 BUDGET REQUEST

Based on the budget forecast for PY 2025 presented in Section 2 and the budget reconciliation for PY 2023 presented in section 4, MCE is requesting a total budget of $6,302,724 for the DAC-GT and CS-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2025

	DAC-GT	CS-GT	Total
Budget Carry-over from PY 2023	$ 1,117,150	$ (271,411)	**$ 845,739**
Budget Forecast for PY 2025	$ 5,456,985	$ -	**$ 5,456,985**
TOTAL	**$ 6,574,135**	**$ (271,411)**	**$ 6,302,724**

6. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports existing program capacity and customer enrollment numbers as of December 31, 2023 in Table 4 below. In PY 2023, enrolled customers were served with an interim solar resource, as discussed above.

Table 4: Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2023

Category	DAC-GT	CS-GT
Existing program capacity (MW)	4.646	0
Participating customers (#)	3,265	0

In Table 5, MCE reports forecasted capacity and customer enrollment for PY 2025. As noted above, MCE estimates that the dedicated project to serve existing DAC-GT will come online in early 2026. MCE plans to solicit a new project to serve the expanded DAC-GT capacity granted in D.24-05-065, but does not anticipate this project will come online during PY 2025. MCE plans to enroll additional customers under the expanded capacity using an interim resource until a new resource can be procured.

Table 5: Forecasted Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2025

Category	DAC-GT
Existing program capacity (MW)	4.646
Additional program capacity to be procured (MW)	3.609
Total program capacity (MW)	8.249
Estimated customer enrollment (#)	5,805

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Marin Clean Energy
ELC (Corp ID 6)
Status of Advice Letter 77E
As of July 26, 2024

Subject: RE: Notice of Marin Clean Energy's Small Business Energy Advantage Program Launch

Division Assigned: Energy

Date Filed: 06-24-2024

Date to Calendar: 07-01-2024

Authorizing Documents: D2105031

Authorizing Documents: D2306055

Disposition:	**Accepted**
Effective Date:	**07-24-2024**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Wade Stano
4154646024 XT104
wstano@mcecleanenergy.org

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

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July 29, 2024

Attorney for the
Joint Community Choice Aggregators and
City and County of San Francisco

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
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REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC or "Commission") *Administrative Law Judge's Ruling Directing Responses to Questions Regarding Implementation of Decision 24-05-065* dated June 5, 2024 ("ALJ Ruling" or "Ruling"), Ava Community Energy ("Ava"), Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Reply Comments.

The Joint CCAs are encouraged by the robust participation of a variety of stakeholders in the development of the implementation details of the Community Renewable Energy ("CRE")

Program as adopted in Decision ("D.") 24-05-065 ("the Decision"). At the same time, the variation in the many proposals regarding the structure of the tariffs, developer compensation, and customer incentives may be difficult to reconcile into a single proposal. As a threshold matter, the Joint CCAs would like to highlight that California already has a well-functioning community solar program, the Disadvantaged Communities ("DAC") Green Tariff ("DAC-GT") program. The Joint CCAs strongly recommend that the new CRE Program be modeled after the existing DAC-GT program to ensure consistency across community solar programs in California and to achieve significant administrative efficiencies considering the limited program funding. The following Reply Comments are submitted with this goal in mind and focus on three core topic areas: (1) CCA participation under the CRE Program; (2) developer compensation; and (3) customer enrollment and bill credit.

II. REPLY

A. CCA PARTICIPATION

i. Assembly Bill 2316 and the Decision Authorize CCAs and IOUs to Administer CRE Programs on Behalf of Their Customers

The Commission should disregard comments by Southern California Edison Company ("SCE") stating that the CRE Program should be administered by the Investor Owned Utilities ("IOUs") on behalf of all customers including bundled, community choice aggregator ("CCA") and direct access customers.[1] SCE argues that CCAs cannot contract for, and administer, CRE projects under the CRE Foundational Tariffs. SCE further argues that because CCA participation would be voluntary, allowing a CCA's tariff to serve as a Foundational Tariff for the CRE Program would not ensure all CCA customers can participate.[2]

---

[1] Opening Comments of Southern California Edison Company on ALJ Ruling ("SCE Opening Comments") at 10.

[2] SCE Opening Comments at 22.

Assembly Bill ("AB") 2316 makes clear that CCAs and electric service providers ("ESPs") may participate in any new community renewable energy program established by the Commission.[3] Additionally, the Decision explicitly states that "CCAs are permitted to participate in the new community renewable energy program" and, as such, "the foundational tariffs will need to be revised to accommodate this participation."[4] The Decision further confirmed that a future ruling on the details of the CRE Program would include questions around the process for CCA participation in the program, as well as which CCA tariffs would be eligible for the program.[5] These provisions clearly outline that CCAs are permitted to participate in the CRE Program if they decide to do so. As such, it is not relevant whether CCAs may currently offer the Foundational Tariffs, as the Decision is clear that the Foundational Tariffs must be revised to ensure CCA participation.

In addition to being contrary to statute and the Decision, SCE's proposal is not in line with the other IOUs' proposals. San Diego Gas & Electric Company ("SDG&E"), for example, is opposed to serving unbundled customers in SDG&E's service territory, further stating that SDG&E supports CCAs "being able to offer whatever choices and programs to customers that they would like to; expanding customer choice."[6] SDG&E further states that CCAs should have the authority to market the CRE Program directly to their customers without creating confusion.[7] Pacific Gas & Electric Company ("PG&E") also supports CCAs offering the CRE Program to

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[3] *See* Pub. Util. Code Section 769.3(b)(2)(B).
[4] D.24-05-065 at 148.
[5] *Id*. at 151.
[6] Comments of San Diego Gas & Electric Company Per ALJ Ruling ("SDG&E Opening Comments") at 4.
[7] SDG&E Opening Comments at 3-4.

their customers.[8] Many parties agree.[9] Pursuant to AB 2316 and the Decision, a CCA must be able to administer the CRE Program on behalf of their own customers if they elect to do so.

ii. Program Funding Should be Allocated to Participating Load Serving Entities Based on Load Share

As noted in parties' Opening Comments, the program capacity for the CRE Program is implicitly limited due to the public funding available for the program.[10] While the Decision doesn't establish an explicit program cap for the CRE Program, as noted in Opening Comments, the Joint CCAs calculate that the allocated funding amount will effectively limit the CRE Program to around 50 MW.[11] Taking into account the limited funding, and therefore, limited program capacity, the Commission should determine a methodology for allocating either the available funding or capacity to the participating load serving entities ("LSEs") administering the CRE Program. While many parties in Opening Comments focused on the allocation of funds among customers and developers in response to the ALJ Ruling, it is equally important to consider the allocation of funds among each LSE, or program administer.[12] In general, the Joint CCAs support Opening Comments stating that participating LSEs should be allocated a

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8 Opening Comments of Pacific Gas and Electric Company in Response to ALJ Ruling ("PG&E Opening Comments") at 17.

9 *See* Comments of Dimension Renewable Energy on ALJ Ruling ("Dimension Opening Comments") at 25 ("CCAs have the ability to develop their own wholesale energy contracts and tariffs for enabling this program"); Comments of the Solar Energy Industries Association on the Implementation of D.24-05-065 ("SEIA Opening Comments") at 23 ("CCAs should have full authority to manage their own CREP procurement and the disbursement of their share of incentive funds to projects and subscribers"); Clean Coalition Comments on ALJ Ruling ("Clean Coalition Opening Comments") at 10 ("CCAs should have the flexibility to develop FITs with additional compensation beyond what is provided in ReMAT or the SOC").

10 SCE Opening Comments at 4 ("Given the current funding that is available, the CRE program should organically start smaller than it may potentially be as more funding materializes…"); *see also* SEIA Opening Comments at 18-19.

11 Opening Comments of the Joint CCAs on ALJ Ruling ("Joint CCA Opening Comments") at 6.

12 *See* ALJ Ruling at 4-5, Question 4.

proportional share of non-rate payer funding based on their respective load shares within the state.[13]

Specifically, the Joint CCAs propose (1) that available program funding for the CRE Program be allocated among the participating LSEs, and (2) that the funding be split between participating LSEs based on load share following the process described below. First, the Joint CCAs believe that as the program funding is the limiting factor for the CRE Program, allocating the funding, rather than capacity, provides a simpler approach than calculating a capacity cap based on the available funding and, in turn, allocating that capacity among the LSEs. Second, the Joint CCAs believe the load share approach is a reasonable and fair methodology for allocating program funding as this method encourages appropriate resource distribution based on the demand each LSE serves.[14]

Further, as mentioned above in Section II.A.i., CCAs and ESPs are permitted to participate in the CRE Program if they elect to. It is important to note that this includes all CCAs and ESPs, not just those CCAs currently administering a DAC-GT program. Under the Joint CCAs' proposal in Opening Comments, and as is consistent with AB 2316, CCAs [and ESPs] would have 180 days upon the issuance of a second decision in this proceeding to submit their own CRE Program tariffs through a Tier 2 Advice Letter, thereby notifying the Commission of the intent to participate in the CRE Program.[15] Once all LSEs have indicated their interest in offering the CRE Program, available public funding would then be split among participating LSEs based on each LSEs' load share.

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13 *See* Dimension Opening Comments at 7; Valta Energy Comments on ALJ Ruling ("Valta Opening Comments") at 1; SEIA Opening Comments at 23.

14 *See* Valta Opening Comments at 1.

15 *See* Pub. Util. Code § 769.3(b)(2)(B); *see also* Joint CCAs Opening Comments at 22.

B. DEVELOPER COMPENSATION

i. Foundational Tariffs Must be Updated to Include Energy Storage

Many parties highlight in Opening Comments the importance of incorporating energy storage under the CRE program and provide a variety of proposals of how energy storage should be compensated under the program.[16] The Joint CCAs would like to take this opportunity to further elaborate on their proposal made in Opening Comments regarding the treatment of energy storage under the CRE Program. The Joint CCAs believe that the Decision gives the Commission the authority to update the existing Foundational Tariffs to align them with the rules and requirements of the CRE Program, including the inclusion of solar + storage projects.[17] The Joint CCAs propose that there be two "CRE Program Tariffs" created by each LSE offering the CRE Program – one CRE Program tariff offering standard pricing for solar only resources ($/kWh for energy produced) and one CRE Program tariff offering standard pricing for solar + storage resources ($/kWh for energy produced by solar system *and* $/kW-month for the capacity provided by the storage system). The Commission would set the pricing/developer compensation under both CRE Program Tariffs, i.e. the Commission would also establish the "base payment" for the energy storage resource for co-located solar + storage systems. For solar + storage systems, both the base energy and capacity payments (if the project has deliverability) would be paid by ratepayers as they reflect costs that the LSEs incur if they were to procure solar + storage resources outside of the CRE Program. Only adders to the developer compensation that go above

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[16] *See* D.24-05-065 at 169, OP 1(i) ("Storage – The community renewable energy program tariff shall allow for co-located solar and storage."); *see also* Valta Opening Comments; Dimension Opening Comments; SEIA Opening Comments; Cypress Creek Opening Comments; Cal Advocates Opening Comments; CCSA Opening Comments.

[17] *See generally id*. at 169, OP 1 (describing the adopted elements of a community renewable energy program).

and beyond the usual procurement costs (a concept called "above market generation costs" under the DAC-GT program) would be recovered by CRE Funding.[18]

ii. The Commission Should Facilitate a Working Group to Establish a Methodology for Developer Compensation Beyond the Base Payments Provided by the Foundational Tariffs

The majority of parties highlight in Opening Comments that additional "adders" must be provided beyond the base payment provided by the Foundational Tariffs to allow for local, distributed project development under the CRE Program.[19] However, there is currently no alignment on the methodology that should be used to establish the level of those adders. Opening Comments include a range of proposals for calculating the adders including, for example, proposals based on the Cost of Renewable Energy Spreadsheet Tool ("CREST") model,[20] a reverse auction mechanism,[21] a set adder of 5%,[22] a comparison to DAC-GT procurement costs,[23] or a "missing money" revenue requirement calculation.[24] The Joint CCAs support the further exploration of the proposed methodologies and suggest the Commission give parties the opportunity to present their proposals in more detail in working group sessions. Based on the discussions in the working group sessions, the Commission and parties may decide on the most

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[18] "CRE Funding" refers to the funding set aside in the Decision for the CRE Program including the $33 million appropriated to the Commission by AB 102 for community energy renewable program usage and storage-backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding.

[19] *See e.g.*, Opening Comments of the Joint CCAs; Opening Comments of the Coalition for Community Solar Access on ALJ Ruling ("CCSA Opening Comments"); Opening Comments of The Utility Reform Networks on the ALJ Ruling ("TURN Opening Comments") at 5; Opening Comments of the Public Advocates Office on ALJ Ruling ("Cal Advocates Opening Comments") at 10; SCE Opening Comments; PG&E Opening Comments.

[20] CCSA Opening Comments at 30.

[21] TURN Opening Comments at 5; Cal Advocates Opening Comments at 10.

[22] SCE Opening Comments at 3.

[23] PG&E Opening Comments at 12.

[24] SEIA Opening Comments at 8.

appropriate valuation methodology to establish the "adders" provided to developers under the CRE Program.

iii. Upfront Payments to Developers Would Require Established Guardrails to Ensure Proper Use of Funds

Several industry representatives propose that a portion of the developer compensation should be paid "upfront," presumably once a project has reached its Commercial Operation Date ("COD").[25] The Joint CCAs have concerns about this proposal and recommend that, if such a proposal were to be adopted, specific guardrails must be established to ensure the funds are appropriately used.

Providing upfront payments to developers poses risks to an LSE as payments are made in advance of the delivery of services under the contract. There could be performance issues with the project throughout the duration of the contract term that could prove challenging to address if payments had already been made. Additionally, stakeholders reference incentive programs for behind-the-meter ("BTM") resources as examples for upfront incentives (such as the California Solar Initiative ("CSI")).[26] This is not a direct comparison as those solar projects operate on a much smaller scale. With significantly larger project sizes under the CRE Program come increased costs, and therefore, increased potential risk when providing upfront incentives and an increased need to protect against those risks.

The risks and challenges mentioned above, absent proper guardrails, could result in long and cumbersome legal processes to claw back already paid upfront incentives from developers for non-performance under a project, or otherwise risk depletion of CRE Funding without CRE Projects performing as projected. Any claw back provisions or other methodologies in the event

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[25] *See e.g.* CCSA Opening Comments at 30; SEIA Opening Comments at 18; Dimension Opening Comments at 9-10; Clean Coalition Opening Comments at 4-5; Valta Opening Comments at 2-3.

[26] Dimension Opening Comments at 10.

of delay or non-performance under a project should therefore be carefully vetted and determined through parties in this proceeding if the Commission were to consider adoption of this proposal. For example, any upfront incentives that are clawed back from a developer, such as in the scenario described above, should be returned to the LSE administering the CRE Program.

The Joint CCAs acknowledge the challenge provided by the Solar for All programs' five-year performance period. However, when looking more closely into the language in the Environmental Protection Agency's ("EPA") Request for Applications ("RFA") for the Solar for All Program (EPA-R-HQ-SFA-23-01), EPA notes that "[a]ll activities funded with the initial grant award must be completed within the negotiated program performance period of up to five years, meaning **all program grant funds must be deployed** [emphasis added] as described in the application."[27] The Joint CCAs note that there could be a variety of definitions for the "deployment" of grant funds. For example, one could argue that grant funds are "deployed" if they are set aside for a particular solar (or solar + storage resource) for its entire performance term (e.g. 20 years). More specifically, an LSE could forecast the payments to the developer paid by Solar for All funding upon COD of the resource as established in the power purchase agreement terms and/or the CRE Program tariffs. This funding could then essentially be "set aside" for the project in the utilities' balancing accounts and would be paid out to the developer per the standard contract terms. Such a process could possibly fulfill the requirement of the EPA to "deploy" the grant funds within 5 years. The Joint CCAs are hopeful that the California Energy Commission ("CEC") (the implementing agency of Solar for All funding in California) can work with the EPA to find a workable solution for community solar in California.

[27] *See* EPA Solar for All RFA at 26, available at https://www.grants.gov/search-results-detail/348957

C. CUSTOMER ENROLLMENT AND BILL CREDIT

i. Program Administrators Should Enroll All CRE Program Participants

CRE Program enrollment of eligible customers should only be the responsibility of the LSEs administering the program. In Opening Comments, Dimension proposes that projects would be responsible for subscribing up to 25% of the subscribers in that project while the LSE would be responsible for the other 75%.[28] Dimension provides that "a division of labor for customer acquisition and management between the solar + storage project and the utility best balances the goals of [Solar for All], the non-energy benefits of community solar (such as community engagement and workforce development), and the limited funding available to support customer savings."[29] However, this approach would likely create confusion and unnecessary administrative burdens. It is simpler and more cost-effective for LSEs to be responsible for all customer enrollment under the CRE Program as proposed by the Joint CCAs, as well as other parties, in Opening Comments.[30]

Additionally, TURN proposes a statewide third-party administrator to manage enrollment and provide customer-facing information about the CRE Program. TURN argues that this "would provide a uniform engagement and education experience for customers of different [LSEs]" and that there "are likely efficiencies with using a single entity for this task rather than spreading it across multiple utilities and CCAs."[31] The Joint CCAs fundamentally disagree with the recommendation to impose a third-party administrator to manage any CRE Program enrollment or promotion of the program. As the Joint CCAs have noted multiple times throughout this

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[28] Dimension Opening Comments at 5-6.
[29] *Id*. at 5.
[30] *See* Joint CCAs Opening Comments; *see also* SCE Opening Comments at 26-27.
[31] TURN Opening Comments at 16.

proceeding, a centralized marketing entity would not be able to effectively serve the local communities like CCA program administrators can.[32] In fact, providing a "uniform" engagement and education experience, as suggested by TURN, would severely limit a main benefit of CCA participation in the CRE Program, namely, the ability of CCAs to adapt the CRE Program to the needs of their local communities.

ii. CRE Program Bill Credits Should be Provided to Low-Income Customers Only

Multiple parties advocate for bill credits being provided to only low-income customers for various reasons, including limited funding.[33] However, PG&E proposes to provide bill credits to low-income customers, as well as Title 24 customers. PG&E suggests that this is appropriate given "the statutory focus of AB 2316 on both low-income customers and consistency with Title 24."[34] While the Joint CCAs agree that there should be a focus under the CRE Program on the *enrollment* of customers looking to fulfill Title 24 compliance, the Joint CCAs do not believe that it is appropriate to give *bill credits* to Title 24 customers. The Joint CCAs do not believe that consistency with Title 24, as required by AB 2316, requires a bill credit for Title 24 customers.[35] However, under the Joint CCAs' proposal as outlined in Opening Comments,[36] non-low-income customers participating in the CRE Program and seeking Title 24 compliance could achieve Title 24 compliance at no additional cost. This, in and of itself, is a substantial benefit and incentive in

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[32] *See e.g.* Exhibit JCCA-02: Prepared Rebuttal Testimony on Behalf of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Rebuttal Testimony")

[33] *See* CCSA Opening Comments at 35 ("CCSA does not recommend the Commission establish a minimum bill savings for non-low-income subscribers"); SCE Opening Comments at 4 (proposing that the CRE program should use the external funding to provide bill credits only to low-income subscribers).

[34] PG&E Opening Comments at 2.

[35] *See* Pub. Util. Code Section 769.3(c)(1) (stating that a new community renewable energy program must be complementary to, and consistent with the requirements of Title 24 with consultation of the California Energy Commission).

[36] Joint CCAs Opening Comments at 17.

pursuing and achieving Title 24 compliance. Furthermore, the Joint CCAs support providing the maximum amount of bill support possible for low-income customers given the limited funding under the CRE Program.[37]

Finally, the CRE Funding currently available for the program is limited to funding bill credits for low-income customers and those located in disadvantaged communities only; namely the Solar for All funding is limited to low-income and disadvantaged communities[38] and the $33 million appropriated to the Commission are intended to "support disadvantaged community renewable generation and storage-backed renewable generation programs."[39] For all of these reasons, the Joint CCA recommend that bill credits should only be provided to low-income customers under the CRE Program.

iii. The "Revenue Share" for Low-Income Customers Should be Set as a 20% Discount off of the Electric Bill

In Opening Comments, the Joint CCAs supported SCE's proposal to provide low-income subscribers with an incentive based on 20% of the power purchase agreement price provided under the specific CRE project that the customer subscribes to in an effort to approximate the interest of the Commission to enable a "project revenue share" for subscribing customers.[40] However, upon further review of the Solar for All funding requirements, the Joint CCAs believe that low-income customers must be offered a minimum 20% discount off of their bill for the CRE program to be eligible for Solar for All funding ("Delivering a minimum of 20% household savings....; household savings is defined as 20% of the average household electricity bill in the

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[37] *See* Joint CCA Opening Comments at 8-9 (describing the funding limitations of the CRE Program).

[38] *See* EPA Solar for All RFA at 26, available at https://www.grants.gov/search-results-detail/348957.

[39] AB 102, Budget Act of 2023, Section 244.

[40] *See* Joint CCA Opening Comments at 15.

utility territory").[41] The CEC, as the implementing agency of the Solar for All funding in California, should discuss with EPA if this could be interpreted as a 20% bill discount of a specific customers' otherwise applicable tariff (instead of the average) as is customary under the DAC-GT program. If this were to be feasible, the implementation of the bill discount under the CRE Program would be significantly streamlined and implementation costs would be significantly reduced, as it would simply follow the existing bill discount methodology under the DAC-GT programs. It would also provide more equality between low-income customers participating in the various community solar programs in California.

III. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

July 29, 2024

Respectfully Submitted,

/s/ Brittany Iles

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[41] *See* EPA Solar for All RFA at 12, available at https://www.grants.gov/search-results-detail/348957.

Docket No.: A.24-03-018

Exhibit No.: CalCCA-01

Date: July 29, 2024

Witness: Brian Dickman

PREPARED DIRECT TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
IN PACIFIC GAS AND ELECTRIC COMPANY'S DIABLO CANYON POWER PLANT 2025 FORECAST PROCEEDING

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I. INTRODUCTION AND SUMMARY OF TESTIMONY

The California Community Choice Association (**CalCCA**) presents this direct testimony in the *Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023, through December 31, 2025, and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees* (**Application**). This testimony has been prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment A.

CalCCA has a particular interest in the Diablo Canyon Power Plant's (**DCPP**) extended operations because costs of extended operations will be recovered from customers of all load-serving entities (**LSEs**) subject to the California Public Utilities Commission's (**Commission**) jurisdiction, including customers of community choice aggregators (**CCA**) that are members of CalCCA. This testimony focuses on the following issues in Commissioner Douglas' June 18, 2024, Scoping Ruling:[1]

2. Whether the calculation of the non-bypassable charge and rate proposals by Pacific Gas and Electric Company (**PG&E**), Southern California Edison Company (**SCE**), and San Diego Gas and Electric Company (**SDG&E)** comply with Decision (**D.**) 23-12-036 and should be approved.
3. Whether PG&E's proposal complies with the implementation of the methodology established by D.23-12-036 for allocating the RA attributes and GHG-Free energy associated with DCPP's extended operations.

[1] *See* Application (**A.**) 24-03-018, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 3-4 (June 18, 2024) (2024 Scoping Ruling).

4. Whether PG&E's proposed volumetric performance fees (**VPFs**) spending plan for the November 3, 2024, to December 31, 2025, period complies with Pub. Util. Code section 712.8(s)(1) requirements and should be approved.

Based on my review of PG&E's Application, supporting workpapers, and responses to discovery, I make the following recommendations:

- The Commission should reject PG&E's proposal to modify the allocation of resource adequacy (**RA**) attributes and greenhouse gas-free (**GHG-Free**) energy because it does not comply with D.23-12-036.
- The Commission should require PG&E to include analysis of any under- or over-collections in the Diablo Canyon Extended Operations Balancing Account (**DCEOBA**), along with detailed supporting information, as part of future DCPP Forecast applications and the Tier 3 Advice Letter true-up process.
- The Commission should adopt principles to ensure projects funded with Volumetric Performance Fee (**VPF**) revenue benefit the maximum number of customers possible, to prioritize spending on electric distribution projects to help reduce upward pressure on distribution rates, and to de-prioritize spending on PG&E's generation assets to avoid competitive issues with other LSEs in its service territory. Further, when presenting proposed project funding plans, PG&E should be required to explain how it satisfied the above principles and to demonstrate which stakeholders benefit from the selected projects.
- PG&E should be required to revise its planned uses of VPF funding in 2025 to: 1) remove any expenditures (or possible expenditures) related to its gas line of business, 2) remove expenditures on generation-related projects, and 3) update

expenditures on specified projects along with a demonstration that it selected eligible projects that benefit the largest number of customers possible.

II. BACKGROUND ON DCPP RATEMAKING AND BENEFIT ALLOCATION DURING EXTENDED OPERATIONS

In this inaugural DCPP Forecast Application, PG&E seeks approval of the net costs of DCPP extended operations from September 1, 2023, through December 31, 2025. Net costs will be recovered from customers of all Commission-jurisdictional LSEs through the Diablo Canyon Non-Bypassable Charge (**DCNBC**). Pursuant to the statutory framework established in Senate Bill (**SB**) 846, certain costs and benefits of DCPP extended operations will be shared with customers of all LSEs, while other costs and benefits of DCPP extended operations will remain only with customers of LSEs in PG&E's service territory. PG&E summarized its requested cost recovery for the initial forecast period (2023 – 2025) in Table 12-3 of its testimony, where it identified the costs to be recovered 'Statewide' and the 'PG&E-Specific' costs to be recovered from customers in PG&E's service territory.[2]

Calculation of the DCPP net costs begins with Operational Revenue Requirement, which includes operation and maintenance expense, annual project costs (i.e., ongoing plant expenditures that would be capitalized under continued plant operations), fuel costs, employee retention expense, and taxes. As authorized in D.23-12-036, PG&E also includes in Operational Revenue Requirement the cost of RA substitution capacity it must provide as the DCPP operator during periods when the DCPP units are on planned outage in accordance with California Independent System Operator (**CAISO**) tariffs.[3] Operational Revenue Requirement is a Statewide cost recovered from all customers.

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[2] PG&E Supplemental and Errata Testimony, page 12-7, Table 12-3.
[3] D.23-12-036, pp. 86-87.

Next, SB 846 entitles PG&E to recover certain fees in lieu of a rate-based return typically recovered on utility generating assets and authorizes PG&E to establish a fund to cover the cost of replacement power during unanticipated plant outages. PG&E identifies these Statutory Fees as the Management Fee, the Volumetric Performance Fee, and Liquidated Damages. Cost recovery for Statutory Fees varies as follows:

- The Management Fee is a fixed payment to PG&E of $50 million (in 2022 dollars) for each unit for each year of extended operations of DCPP.[4] This cost escalates annually and is recoverable from all Statewide customers.
- A VPF of $6.50 (in 2022 dollars, escalating annually) for each megawatt hour (**MWh**) generated by Diablo Canyon is to be recovered from all Statewide customers.
- An additional $6.50/MWh (in 2022 dollars, escalating annually) is to be recovered only from customers in PG&E's service territory.[5] Revenue collected from customers to recover the VPF is to be used to fund projects in PG&E's service territory that meet specified critical public purpose priorities.[6]
- Liquidated Damages are authorized to be recovered at $12.5 million per month per unit to fund a balancing account of $300 million.[7] The Liquidated Damages Subaccount will be used to cover the costs of replacement power should PG&E have an unplanned outage for which it is determined that PG&E did not meet

[4] Pub. Util. Code Section 712.8(f)(6).
[5] Pub. Util. Code Section 712.8(f)(5).
[6] Pub. Util. Code Section 712.8(s)(1).
[7] Pub. Util. Code Section 712.8(g).

the reasonable manager standard.[8] These costs are recovered from all Statewide customers. However, if there are funds remaining in the Liquidated Damages Subaccount at the end of extended operations the balance will be returned only to customers in PG&E service territory.[9]

On an annual basis, wholesale market revenue earned by selling DCPP energy into the CAISO market will be used to offset the DCPP Total Costs. This CAISO Market Revenue reduces the total revenue requirements that must be recovered from Statewide customers.[10] To the extent there is excess CAISO Market Revenue, meaning the wholesale market revenue exceeds the DCPP Total Costs, the excess revenue is to be returned only to customers in PG&E service territory.[11] For customers outside PG&E's service territory, the Commission may credit wholesale market revenue up to their respective annual costs and expenses, but not beyond that amount.

In D.23-12-036 the Commission authorized PG&E to true-up actual DCPP extended operations costs, net of CAISO Market Revenue, through the DCEOBA. The process of setting rates to recover the costs of extended operations at DCPP will involve two interrelated proceedings. Each year PG&E will seek approval of DCPP's projected net costs using a forecast of extended operations over the subsequent year. In that annual application PG&E will also request approval for the inclusion in rates of under- or over-collections in the DCEOBA. This process—the recovery of forecast costs combined with a rolling true-up—resembles the Energy Resource Recovery Account (**ERRA**) Forecast

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[8] Pub. Util. Code Section 712.8(i)(1). In the event that the balance of the Liquidated Damages Subaccount is reduced due to an unplanned outage, PG&E is authorized to recover funds to replenish the balance up to $300 million. Pub. Util. Code Section 712.8(i)(2).

[9] Pub. Util. Code Section 712.8(u).

[10] Pub. Util. Code Section 712.8(h)(1).

[11] Pub. Util. Code Section 712.8(h)(3).

process, with the key difference being that amortizations of under/over-collections included in the annual DCPP filings will not exceed 115 percent of the forecasted costs.[12] PG&E is also required to file an annual Tier 3 Advice Letter reporting on the actual extended operations costs and revenue recorded to DCEOBA and whether the recorded DCEOBA spend for extended operations exceeded 115 percent of the forecast for that year.[13] These regulatory processes must be harmonized not only to ensure the net costs are appropriately calculated and collected from customers, but also that the benefits from extended operations are appropriately allocated.

The current Application, and future annual DCPP forecast proceedings, will also establish the allocation of benefits associated with DCPP's extended operations consistent with D.23-12-036. In that Decision, the Commission adopted a process mirrored after the Cost Allocation Mechanism (**CAM**) to allocate DCPP's RA capacity to LSEs responsible for paying the costs of extended operations. Like CAM, the allocation methodology set forth in D.23-12-036 ensures that all cost-responsible customers, regardless of their LSE, share the benefits of DCPP's RA capacity during DCPP's extended operations. For similar reasons, D.23-12-036 also requires PG&E to allocate DCPP's GHG-Free energy to cost-responsible LSEs. This allocation will be based on each LSE's load forecast such that those LSEs are able to count DCPP's GHG-Free attributes towards their Power Content Labels (**PCL**) under the California Energy Commission's (**CEC**) Power Source Disclosure (**PSD**) program.

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[12] PG&E Supplemental and Errata Testimony, page 10-4, line 20 through page 10-5, line 9.

[13] *Id*., page 10-5, lines 10-23; *see* Attachment B, PG&E Response to CalCCA data request 2.07.

III. PG&E'S PROPOSAL TO MODIFY THE ALLOCATION OF DCPP RA ATTRIBUTES AND GHG-FREE ENERGY DOES NOT COMPLY WITH THE METHODOLOGY ESTABLISHED BY THE COMMISSION IN D.23-12-036.

In this proceeding, PG&E must implement the benefit allocation methodologies established in D.23-12-036. D.23-12-036 clearly directs PG&E to allocate the RA benefits of DCPP extended operations among LSEs in PG&E, SCE, and SDG&E service areas on the basis of 12-month coincident peak load (**12 CP**).[14] It also directs PG&E to offer LSEs that pay for DCPP extended operations the ability to accept a share of DCPP's GHG-Free attributes, allocated according to each LSE's proportionate share of customer load.[15]

PG&E's proposed allocation of RA and GHG-Free attributes does not follow the benefit allocation methodologies D.23-12-036 established. Instead, PG&E proposes its own new allocation methodology. PG&E's proposed methodology begins by allocating extended operations costs to IOU service territories based on 12 CP, but then PG&E adjusts the allocated costs to include, for PG&E, the statutory fees required to be paid by only customers in its service territory. PG&E proposes to calculate the ratio of these adjusted costs by IOU service territory compared to the total costs and use that ratio to allocate RA and GHG-Free attributes.

In support of its proposal, PG&E claims that "D.23-12-036 did not consider the higher costs to customers in PG&E's service area" during DCPP extended operations.[16] However, PG&E's proposal ignores that 1) the purpose of this proceeding is to implement the methodologies established in D.23-12-036, not propose new allocation methodologies; 2) the Commission is not required to adjust allocation rates considering the "higher costs

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[14] D.23-12-036, p. 137, Ordering Paragraph 9.
[15] *Id.*, p. 131, Conclusions of Law 41-42.
[16] PG&E Supplemental and Errata Testimony, page 2-21, lines 7-9.

to customers in PG&E's service area", and 3) the Commission considered multiple benefits that will accrue specifically to customers in PG&E's service territory when it established RA and GHG-Free allocation methodologies in D.23-12-036.

A. The Commission Adopted Methodologies for Allocating Costs and Benefits of DCPP Extended Operations in D.23-12-036.

SB 846 extended the life of DCPP for the benefit of all of California's electric customers while designating a single IOU, PG&E, as the operator. Public Resources Code Section 25548.7 states, "Continued operation of the Diablo Canyon powerplant as provided in this chapter is in all respects for the welfare and the benefit of the people of the state…" Based on this rationale, SB 846 also alters the cost recovery framework for DCPP during extended operations. SB 846 entitles PG&E to recover the reasonable and necessary costs to operate DCPP beyond the current expiration dates, net of market revenue from DCPP operation. With limited exceptions, SB 846 specifies that DCPP extended operations costs are to be recovered from customers of all jurisdictional LSEs in California.

The rationale and framework for extending DCPP operations described in SB 846 is similar to the CAM concept originally established by the Commission in D.06-07-029. The Commission instituted CAM as a mechanism to streamline procurement of critical new resource capacity for the benefit of multiple customer groups (e.g., bundled and unbundled customers). Like CAM, the allocation methodology set forth by D.23-12-036 ensures that all customers, regardless of their LSE, share the benefits of DCPP's RA capacity during the plant's extended operations in a manner proportional to their contribution to the system's peak demand. This approach maintains a balanced distribution of costs and benefits, where each LSE pays for the costs of the resource, net of revenue earned in the wholesale market, and each LSE receives RA credits based on its share of the

12-month coincident peak. Table 1 below provides the 12 CP allocation ratios as approved in D.23-12-036, along with the corresponding allocation of statewide extended operations costs and RA capacity.

Table 1: 12 CP Allocation of Statewide Costs and RA Benefits

	12-CP Allocation	Statewide Costs* ('000s)	Approved RA Allocation (MW)
PG&E	45.0%	$ 506,951	1,026
SCE	44.7%	$ 504,122	1,019
SDG&E	10.3%	$ 116,052	235
Total	100.0%	$ 1,127,125	2,280

Regarding GHG-Free attributes, D.23-12-036 directs PG&E to use the interim allocation process approved in Resolution E-5111, which allocates GHG-Free energy to LSEs based on load share.[17] Specifically, under the approved method, PG&E determines an LSE's share of GHG-Free energy using an "Allocation Ratio" calculated as the LSE's forecasted load compared to the total forecasted load for customers responsible for the costs of the resources.[18] In R.23-01-007, CalCCA proposed that the Allocation Ratio be calculated to allocate DCPP GHG-Free energy to customers of all paying LSEs using load forecasted in the CEC's California Energy Demand forecast. Table 2 below presents the Allocation Ratio at the IOU service territory level using the CEC's 2023 California Energy Demand forecast of retail sales volume in 2025.

[17] As required by ordering paragraph 10 in D.23-12-036, PG&E filed Advice Letter 7295-E on June 12, 2024, requesting approval of the process for allocating DCPP GHG-Free energy to all Commission-jurisdictional LSEs.

[18] PG&E Advice Letter 5930-E, Appendix P, page 3; approved in Resolution E-5111.

Table 2: Load Share Allocation of GHG-Free Energy

	Approved GHG-Free Allocation Method
PG&E	42.6%
SCE	47.2%
SDG&E	10.2%
Total	100.0%

B. PG&E's RA and GHG-Free Allocation Proposals Do Not Comply with the Methodology Established by D.23-12-036.

PG&E's proposed allocation deviates from the methodology approved in D.23-12-036 by reallocating RA capacity and GHG-Free attributes in a way that shifts benefits to PG&E's service territory. According to PG&E's adjusted allocation proposal, statewide costs recovered from all customers would first be allocated among IOU service territories using 12-month coincident peak load. Rather than stopping there as D.23-12-036 requires, PG&E proposes to add costs specific to PG&E service territory to PG&E's allocated total (i.e., the additional $6.50/MWh fee in 2022 dollars paid for solely by PG&E's service area customers), and then use the revised *costs* by IOU service territory to derive new allocation factors applicable at the service territory level.[19] PG&E recommends that Energy Division then use the revised RA allocation to IOU service territories to determine each LSE's allocated share of DCPP RA within each utility's service area.[20] PG&E's proposal and the impact it would have on RA allocation is illustrated in Table 3 and Table 4 below.

[19] PG&E Supplemental and Errata Testimony, page 2-21, lines 15-27.
[20] *Id*., page 2-22, lines 7-17.

Table 3: PG&E's Proposal to Modify RA Allocation

	Allocated Statewide Costs ('000s)	Statewide & PG&E Specific Costs ('000s)	PG&E Proposed Allocation %	PG&E Proposed RA Allocation (MW)
PG&E	$ 506,951	$ 586,756	48.6%	1,108
SCE	$ 504,122	$ 504,122	41.8%	953
SDG&E	$ 116,052	$ 116,052	9.6%	219
Total	$ 1,127,125	$ 1,206,930	100.0%	2,280

Table 4: Impact of PG&E's Modified RA Allocation

	Approved 12-CP Allocation	Approved RA Allocation (MW)	PG&E Proposed Allocation %	PG&E Proposed RA Allocation (MW)	Change in Allocation %	Change in Allocation (MW)
PG&E	45.0%	1,026	48.6%	1,108	3.6%	82
SCE	44.7%	1,019	41.8%	953	-2.9%	(66)
SDG&E	10.3%	235	9.6%	219	-0.7%	(16)
Total	100.0%	2,280	100.0%	2,280	0.0%	-

In a similar vein, PG&E proposes that DCPP's GHG-Free energy attributes be allocated to LSEs using the same adjusted allocation ratios for RA capacity.[21] That is, rather than use each LSE's load to determine its share of DCPP GHG-Free energy, PG&E proposes to allocate GHG-Free energy based on its adjusted cost allocation. PG&E's proposed methodology to allocate GHG-Free attributes diverges from D.23-12-036 in that the allocation methodology defined by the decision required PG&E to use the existing method for voluntarily offering a share of the GHG attributes of certain resources to LSEs.[22] Table 5 shows the difference between the approved methodology and PG&E's proposal in this Application.

[21] *Id.*, page 2-23, lines 6-7.
[22] D.23-12-036, p. 90.

Table 5: GHG-Free Allocation Methodologies

	Approved GHG-Free Allocation Method	PG&E Proposed GHG-Free Allocation	Change in Allocation
PG&E	42.6%	48.6%	6.0%
SCE	47.2%	41.8%	-5.4%
SDG&E	10.2%	9.6%	-0.6%
Total	100.0%	100.0%	0.0%

In its reply to protests, PG&E claims it is not undoing or relitigating anything the Commission established in D.23-12-036, it is merely using the Commission-approved methodology as a "basis with an adjustment."[23] PG&E states that it does not disagree with the Commission's 12 CP allocation methodology, it merely seeks to adjust the results. As shown in my testimony, however, PG&E's "adjustment" modifies the allocation methodology for RA and is a wholesale change in the allocation approach for GHG-Free energy. LSEs would receive totally different RA and GHG-Free allocations under the approved methodology versus PG&E's approach.

PG&E's proposal to change the RA and GHG-Free allocation is not in compliance with the methodology adopted by the Commission in D.23-12-036. In fact, PG&E's adjustment to the RA and GHG-Free allocation was never presented in the R.23-01-007 proceeding leading to D.23-12-036, so it clearly was not part of the methodology adopted in that decision. The Commission should reject PG&E's proposed adjustment here and direct PG&E to adhere to the methodology established in D.23-12-036, ensuring that RA allocation is based on each LSE's contribution to the 12-month coincident peak and GHG-Free energy is allocated based on each LSE's load share.

[23] Reply of PG&E to Protests, pp. 10-11.

C. The Approved Allocation Methodology Accounts for the Higher Cost Responsibility in PG&E's Service Area.

Even if PG&E were meant to propose new attribute allocation methodologies in this case, and it was not, the Commission should not adopt PG&E's proposal. There are two reasons for this. First, the statutory section cited by PG&E as permitting the allocation of DCPP's attributes allows, but does not require, the Commission to "consider the higher cost to customers in the operator's service area."[24] Second, the Commission already considered the higher cost to customers in PG&E's service area when it issued D.23-12-036 and established attribute allocation methodologies. Therefore, the Commission need not to do so again.

According to D.23-12-036, almost all the costs related to DCPP extended operations will be allocated to CPUC jurisdictional LSEs based on their contribution to 12-month coincident peak demand. While SB 846 requires customers in PG&E's service territory to pay an additional VPF (to which PG&E points as justification for its modified allocation proposal), it also makes three specific categories of benefits available only to customers in PG&E's service territory. First, only customers in PG&E service territory will receive a credit when DCPP earns wholesale market revenues that exceed the cost of extended operations. Table 6 below demonstrates that, based on the projected market prices included in PG&E's application, PG&E expects DCPP to earn nearly $100 million in excess wholesale revenue in 2026 and nearly $50 million in excess wholesale revenues in 2029. To the extent they materialize, those excess revenues will accrue only to customers in PG&E's service territory—not to any other customer.

[24] PG&E Supplemental and Errata Testimony, page 2-21, lines 4-14. *See also* Pub. Util. Code Section 712.8(q).

Table 6: PG&E Diablo Canyon Above Market Costs/(Excess Revenues)[25]

$ millions	2023	2024	2025	2026	2027	2028	2029	2030
Expense O&M and Projects	$ 17.0	$ 63.6	$ 417.7	$ 593.1	$ 564.8	$ 589.2	$ 485.5	$ 316.1
Nuclear Fuel Expense Amortization			$ 134.0	$ 134.0	$ 134.0	$ 134.0	$ 134.0	$ 134.0
Spent Nuclear Fuel Management (DOELBA Proceeds)					$ (13.1)	$ (13.3)	$ (15.0)	$ (1.0)
Fixed Payment		$ 8.4	$ 70.7	$ 105.7	$ 106.4	$ 107.6	$ 100.0	$ 46.2
Volumetric Performance Fee - Statewide		$ 9.8	$ 70.1	$ 127.8	$ 131.6	$ 127.9	$ 133.5	$ 55.0
Volumetric Performance Fee - PG&E Specific		$ 9.8	$ 70.1	$ 127.8	$ 131.6	$ 127.9	$ 133.5	$ 55.0
A&G Allocation					$ 204.1	$ 209.4	$ 196.9	$ 91.9
Taxes	$ 1.9	$ 8.8	$ 47.6	$ 66.8	$ 67.7	$ 70.1	$ 65.4	$ 37.0
Revenue Fees and Uncollectibles	$ 0.3	$ 0.3	$ 5.1	$ 0.3	$ 1.6	$ 3.7	$ 1.0	$ 3.7
Debt Financing Costs		$ 0.2	$ 3.0	$ 0.6	$ 1.5	$ 2.2	$ 2.4	$ 1.2
RA Substitution		$ 8.5	$ 67.9	$ 51.0	$ 42.4	$ 76.4	$ 17.0	$ 33.9
Liquidated Damages Subaccount		$ 25.0	$ 200.0	$ 75.0				
Extended Operation Costs - Statewide	**$ 19.2**	**$ 124.6**	**$ 1,016.1**	**$ 1,154.3**	**$ 1,241.0**	**$ 1,307.2**	**$ 1,120.7**	**$ 718.0**
Extended Operation Costs - PG&E Specific	$ -	$ 9.8	$ 70.1	$ 127.8	$ 131.6	$ 127.9	$ 133.5	$ 55.0
DCPP Generation Market Revenues		$ (113.1)	$ (699.9)	$ (1,250.8)	$ (1,234.2)	$ (1,139.1)	$ (1,167.9)	$ (448.0)
Extended Operation Above Market Costs	**$ 19.2**	**$ 11.5**	**$ 316.2**	**$ (96.6)**	**$ 6.7**	**$ 168.1**	**$ (47.2)**	**$ 270.0**
Generation Volume (GWh)		1,442	10,207	18,183	18,268	17,305	17,612	7,068
CAISO Market Price ($/MWh)		$78.44	$68.57	$68.79	$67.56	$65.83	$66.32	$63.39

Second, only customers in PG&E service territory are entitled to receive funds remaining in the DCPP Liquidated Damages Subaccount at the conclusion of the extended operations period. As background, SB 846 requires all customers from all jurisdictional LSEs to contribute to a $300 million fund tracked in the Liquidated Damages Subaccount and designated to recover the cost of outages at DCPP during the period of extended operations. Per the statute, this Liquidated Damages Subaccount is established to cover the cost of outages occurring due to PG&E's failure to meet the reasonable manager standard.[26] In other words, customers are required to fund this balancing account to cover the cost of

[25] In Table 2-3 of PG&E's testimony, PG&E provided a forecast of DCPP costs, revenue credits and societal benefits during the extended operations period. Table 6 of CalCCA's testimony provides the same forecast from Table 2-3 but is limited to the costs and revenue that will be recovered from customers through the DCNBC (i.e., excluding societal benefits or the value of allocated RA attributes).

[26] Pub. Util. Code Section 712.8(i)(1)

imprudent outages. The cost of unavoidable outages that occur even when PG&E acts as a prudent manager will be recovered from all customers through the DCEOBA. To the extent funds remain in the Liquidated Damages Subaccount at the end of extended operations, the surplus will be refunded only to customers in PG&E's service territory.[27] Through discovery, PG&E confirmed there has only been one instance since 2010 (and none in the last 10 years) where an unplanned outage at a DCPP unit was found to be caused by PG&E failing to meet the reasonable manager standard.[28,29] And even if the Commission directs PG&E to use funds from the Liquidated Damages Subaccount to cover the cost of an outage, PG&E is entitled to replenish the fund by charging all customers.[30] It is therefore likely that customers in PG&E's service territory—and no other customers—will benefit from a $300 million refund after DCPP extended operations.

Finally, SB 846 directed PG&E to use VPF revenue to accelerate or increase spending on critical public purposes.[31] The benefits of those expenditures, such as infrastructure improvements, enhanced reliability, and operational efficiencies, will accrue to customers in PG&E's service territory alone. For example, in the current case PG&E proposes to spend VPF funds on several specific initiatives during 2025, including a pole inspection program, accelerated enhancements of certain activities related to PG&E's hydro assets, and expediting customer interconnections.[32] The proposed Comprehensive Pole Inspection Program identifies PG&E's electric distribution assets most likely to

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[27] Pub. Util. Code Section 712.8(u).

[28] *See* Attachment B, PG&E's response to CalCCA data request 2.13.

[29] *See* Attachment B, PG&E's response to CalCCA data request 2.12. PG&E noted that outages occurring since July 2020 are still pending review in ERRA Compliance proceedings.

[30] Pub. Util. Code Section 712.8(i)(2).

[31] Spending on critical public purpose priorities will only follow offsetting DCPP actual costs > 115% of forecast costs, per D.23-12-036.

[32] PG&E Supplemental and Errata Testimony, pages 9-6 to 9-11.

present a safety or wildfire risk. Accelerated enhancements of hydro asset management, inspection, and maintenance activities is intended to improve management of PG&E's hydro generation fleet. And a third program relates to streamlining processes, implementing new work practices, and contributing funds to upgrade PG&E's enterprise resource planning software, all to expedite customer interconnections and modernize the grid. Each of these uses of VPF funds would exclusively benefit customers in PG&E's service area.

It is true that SB 846 requires customers in PG&E's service territory to pay an additional VPF that Statewide customers are not required to pay. However, it is clear that SB 846 contemplates several specific offsetting financial benefits that will accrue only to customers in PG&E's service territory. Furthermore, CalCCA and others identified these statutory advantages in testimony addressing the allocation of DCPP extended operations costs and benefits in R.23-01-007. For example, in R.23-01-007 I sponsored testimony on CalCCA's behalf wherein I observed that CalCCA's allocation proposals achieve a fair result because customers of LSEs in PG&E's service territory (unlike customers of LSEs *outside* of PG&E's service territory) benefit from surplus wholesale market revenue and the return of excess funds paid into the Liquidated Damages Subaccount by all customers.[33] These statutory provisions are not new and were highlighted by parties prior to the Commission establishing the methodologies for allocating DCPP RA and GHG-Free attributes in D.23-12-036.[34]

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[33] R.23-01-007, CalCCA-01 at 27-29.

[34] PG&E has appealed D.23-12-036. *See* Pacific Gas and Electric Company v. California Public Utilities Commission, Petition for Writ of Review (1st. App. Dist. July 3, 2024). In its Petition, PG&E claims the Commission erred in directing PG&E to use volumetric performance fee revenue to first offset DCPP costs greater than 115% of forecast costs. To the extent PG&E prevails, it will be able to use more

IV. PG&E SHOULD PROVIDE DETAILED VARIANCE ANALYSIS AND WORKPAPERS DURING FUTURE FORECAST APPLICATIONS AND TIER 3 ADVICE LETTER TRUEUPS.

This DCPP Forecast application seeks approval of rates to recover forecasted costs, effective January 1, 2025. Actual costs and revenue related to DCPP extended operations, including customer revenue collected through the DCNBC, will be recorded to the DCEOBA beginning 2025 and will be subject to true-up in subsequent filings. Under- or over-collections in the DCEOBA will be addressed in at least two different proceedings in upcoming years.

In March 2025, PG&E will file a second DCPP Forecast application to review and approve forecast costs for the period January 1, 2026, through December 31, 2026.[35] That application will also include projected over/under-collections in the DCEOBA through the end of 2025 for amortization in rates effective January 1, 2026.[36] Again, this process is intended to be similar to the ERRA Forecast process, with the key difference being that under/over-collections in the DCEOBA will only be included in the DCPP Forecast proceeding to the extent actual expenses are at or below 115 percent of the forecast costs.[37] Actual expenses above 115 percent of forecasted costs are to be identified and reviewed in a separate filing.

PG&E is also required to file an annual Tier 3 Advice Letter reporting on the recorded activity in DCEOBA and whether actual spend for extended operations exceeded

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of the volumetric performance fee revenue it collects towards statutory critical public purpose priorities. It is therefore important the Commission establish reasonable guardrails related to PG&E's use of volumetric performance fee revenues in this proceeding.

[35] PG&E Supplemental and Errata Testimony, page 10-4, lines 21-27.

[36] *See* Attachment B, PG&E's response to CalCCA data request 2.07.

[37] *Id*.

115 percent of the forecast for that year.[38] PG&E does not yet know when it plans to file the first Advice Letter, nor does it have a schedule determined for subsequent filings.[39] Through discovery, PG&E stated that the content of the Tier 3 Advice Letter will be structured similar to the review of procurement-related balancing accounts in the annual ERRA Compliance proceedings.[40] Specifically, the presentation will describe the background and structure of the DCEOBA and its associated subaccounts, detail the activity recorded in the account and subaccounts, and provide a variance analysis comparing PG&E's forecasted costs to actual costs for the record period.[41] To the extent PG&E's actual costs exceed 115 percent of forecast costs, those costs will be subject to a reasonableness review following a yet undetermined process. PG&E has said that it will seek Commission direction on how to conduct a reasonableness review if costs exceed 115 percent of the approved forecast.[42]

Under- or over-collections can occur in the DCEOBA for various reasons, including deviations in extended operations costs, changes in CAISO market revenue due to variations in generation output or market prices, and changes in customer collections resulting from higher or lower customer load. Understanding the cause of these variations in the DCEOBA is critical because all under- or over-collections are not treated the same for cost recovery purposes. For example, if higher retail sales volumes cause an over-collected balance in the DCEOBA, the balance can be returned to all customers causing the over-collection. However, if an over-collection is caused by excess CAISO market

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38 *See* Attachment B, PG&E's response to CalCCA data request 1.27.
39 *See* Attachment B, PG&E's response to CalCCA data request 2.05.
40 *See* Attachment B, PG&E's response to CalCCA data request 2.03.
41 *See* Attachment B, PG&E's response to CalCCA data request 2.06.
42 *See* Attachment B, PG&E's response to CalCCA data request 2.03.

revenue, the balance can only be returned to customers in PG&E's service territory. Because all actual DCEOBA inputs will vary from the forecast, the Commission will need to have a detailed understanding of the drivers of any balance in the DCEOBA account before customer rates can be determined.

CalCCA and other intervenors routinely identify issues or errors in PG&E and other IOU ERRA filings which require remedy prior to ERRA rates being set. The DCNBC would likely be no different. CalCCA is concerned that interested parties may not be provided adequate information or time to review the workings of the DCEOBA, understand the drivers of any balance in the DCEOBA, and ensure under- or over-recoveries are reflected correctly in customer rates. Both filing processes described above are expedited proceedings with limited time for interested parties to review the details of PG&E's calculations. PG&E confirmed that it expects to include the 2025 DCEOBA under- or over-collection in the DCPP Forecast application to set rates for 2026, but it has provided no indication how it will demonstrate that the DCEOBA balance has been properly calculated and assigned to the correct group of customers for recovery.[43]

Additionally, PG&E stated in discovery that SB 846 does not mandate a review and audit of actual costs and revenues[44] and that it intends to limit the workpapers it makes available in the Tier 3 Advice Letter process to a "summarized level."[45] In practice, this will be a significant challenge for parties wishing to review PG&E's filing given the tight timeline for submitting protests, which is only 20 days in a Tier 3 Advice Letter process. Due to the short turnaround and PG&E's initial plan to provide only summary level

[43] *See* Attachment B, PG&E response to CalCCA data request 2.07.
[44] *See* Attachment B, PG&E response to CalCCA data request 1.28.
[45] *See* Attachment B, PG&E response to CalCCA data request 1.29.

workpapers, undertaking a detailed review of the DCEOBA balance and evaluation of under- or over-collections in either the DCPP Forecast proceeding, or the Tier 3 Advice Letter filing will be challenging.

CalCCA recommends that PG&E be required to demonstrate the drivers of under- or over-collected balances in DCEOBA each time it files a DCPP Forecast application or the Tier 3 Advice Letter review. Interested parties should also be provided workpapers with sufficient supporting detail to facilitate a review of the DCEOBA balance and PG&E's evaluation of the drivers concurrent with the DCPP Forecast application or Tier 3 Advice Letter filing. Such reviews ensure that PG&E complies with Commission directives set forth in D.23-12-036 and the requirements of SB 846 prior to including costs in customer rates.

Specifically, CalCCA seeks the opportunity to review PG&E's DCEOBA-related calculations for consistency with tariffs, evaluate the cause of under- and over-collections, and verify that the mechanism is functioning as intended. PG&E is required to provide certain information and data in other similar applications (i.e., ERRA Forecast and ERRA Compliance) in the form of a "Master Data Request." Since review of DCEOBA under- and over-collections must occur during the DCPP Forecast application and Tier 3 Advice Letter process, the Commission should require PG&E to provide the following information (consistent with ERRA applications) with each filing at the time of filing:[46]

1. Workpapers supporting the final (e.g., the October update) forecast revenue requirement and rates from the DCPP Forecast case and any implementing advice letters for the record year.
2. Workpapers demonstrating monthly recorded costs and revenue for each tariff line item in the DCEOBA.
3. DCPP monthly generation volume by unit.

[46] Confidential information would only be provided to parties executing the appropriate non-disclosure agreement with PG&E.

4. DCPP monthly CAISO revenue and costs.
5. Monthly retail revenue recorded for bundled, CCA and direct access customers, for PG&E, SCE, and SDG&E.
6. Monthly billed retail sales volumes for bundled, CCA and direct access customers, for PG&E, SCE, and SDG&E.

The Commission should also require PG&E to prepare a DCEOBA variance analysis (forecast vs. actual), with explanations of material variances from forecast, and present it in the DCPP Forecast case when it requests to roll the DCEOBA balance in rates and the Tier 3 Advice Letter process when it seeks final approval of the DCEOBA balance. The variance analysis should include workpapers with DCEOBA detail by tariff line item, including dollar amounts and underlying volumes.

V. PG&E'S PRIORITIZATION OF VOLUMETRIC PERFORMANCE FEE EXPENDITURES SHOULD FOLLOW PRINCPLES TIED TO SB 846 THAT REFLECT ITS STATEWIDE COST RECOVERY PARADIGM.

According to SB 846, to the extent it is not needed for Diablo Canyon, VPF revenue must be spent to accelerate, or increase spending on, the following public purpose priorities:[47]

(A) Accelerating customer and generator interconnections.
(B) Accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid.
(C) Accelerating building decarbonization.
(D) Workforce and customer safety.
(E) Communications and education.
(F) Increasing resiliency and reducing operational and system risk.

In this proceeding, PG&E proposes both a process to determine the use of VPF revenue it collects going forward, as well as specific uses for VPF revenues it collects in 2025. With respect to process, PG&E proposes a three-step "waterfall" to determine the

[47] Pub. Util. Code Section 712.8(s)(1).

use of VPF revenue.[48] First, PG&E will select specific projects, chosen from the universe of projects compiled as part of its annual corporate planning process, that it believes meet the public purpose priorities listed above and that either require funding incremental to amounts included in a GRC or that are new programs not previously included in a GRC.[49] Based on that list of projects, PG&E will set a total budgeted spend during 2025 that is less than the total expected VPF revenue over that time frame. Second, PG&E earmarks the remaining expected VPF revenue to be used, as available, for unforeseen risk and safety work in certain major work categories.[50] This earmarked contingency funding essentially provides a buffer so that PG&E does not plan to spend VPF revenue that does not materialize due to variation in customer load or DCPP generation. Last, PG&E indicates it will consider using any funds remaining after VPF dollars are spent on the identified projects and contingency events to offset DCPP operating costs, at its discretion.[51]

A. The Commission Should Adopt Principles to Ensure VPF Expenditures Benefit the Maximum Number of Electric Customers.

CalCCA agrees that identifying specific candidate projects for VPF spending is important, and equally important is ensuring there is no double recovery from customers for planned spend already requested in another regulatory proceeding.[52] However, I have several concerns with PG&E's proposed process. First, PG&E's process is inadequate because it identifies projects without considering whether the project's benefits will flow equitably to customers. This is a concern because, by virtue of the unique statutory framework, PG&E will collect VPF revenues from customers across the state but use those

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48 PG&E Supplemental and Errata Testimony, page 9-1, lines 19-31.
49 *Id*., page 9-5, lines 7-24.
50 *Id*., page 9-4, lines 23-32.
51 *Id*., page 9-5, lines 3-6.
52 *Id*., page 9-5, lines 7-10.

revenues to benefit customers in its service territory (as I discussed above). Given that only a subset of cost-responsible customers will benefit from PG&E's use of VPF revenues, it is particularly important PG&E use those revenues in a manner that benefits the greatest number of customers.

Second, PG&E's proposed process allows VPF revenues to be used for projects from any part of its utility business, including its gas department. As proposed by PG&E, the only limitations on a project's eligibility to receive VPF funding is that it must meet one of the public purposes in Section 712.8(s)(1) and not already be fully funded through another regulatory proceeding.[53] Some of the Section 712.8(s)(1) categories, such as 'workforce and customer safety' and 'communications and education' could be broadly applied to any part of PG&E's business, and may therefore divert VPF revenue to fund projects that would otherwise be paid for by PG&E's gas customers.

Third, PG&E's proposed process does not include any guardrails to avoid competitive issues with other LSEs in its service territory. For example, spending funds paid by customers of other LSEs to enhance PG&E's owned generation fleet or offset the cost of PG&E's generation service would give PG&E an unfair competitive advantage over those LSEs.

To remedy these concerns, the Commission should first clarify that VPF funding can only be used to fund projects that satisfy the public purpose priorities in Section 712.8(s)(1) and to cover costs that would otherwise be recovered only from PG&E's *electric* customers. I also recommend the Commission adopt the following principles to guide PG&E in the prioritization of projects funded with VPF revenue:

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[53] *Id*.

1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers.
2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates and accelerate customer and generation interconnections.
3. VPF funds should not be used on projects for PG&E's generation assets until PG&E can show that eligible delivery-related projects are exhausted.

When presenting proposed project funding plans, PG&E should be required to explain how it satisfied the above principles and to demonstrate which stakeholders benefit from the selected projects.

B. PG&E's Planned Uses for VPF Funding Include Projects that Should Not be Allowed or Should be De-Prioritized

Applying the "waterfall" process, PG&E's planned uses for VPF revenue collected in 2025 are summarized in Table 7 below.

Table 7: PG&E's Planned Uses for VPFs Collected in 2025

Program	Estimated Funding
1. Comprehensive pole inspection program	$30-$60 million
2. Accelerating enhancements of asset management, inspection, and maintenance of activities required for safe and reliable operations of hydro system infrastructure	$20-$40 million
3. Accelerating interconnections and actions to reduce operational risk and modernize the grid more efficiently through operating system enhancements	$20-$30 million
4. PG&E contingency uses for safety and risk	$40-$60 million

I have two concerns with the proposed uses of VPF revenues described above. First, Category 4 of PG&E's proposal is funding contingency uses for safety and risk. PG&E indicates the funds in this category will be used for any unforeseen key critical risk and

safety work that would otherwise be done in one of ten major work categories.[54] The eligible major work categories include work on electric transmission and distribution facilities such as corrective maintenance, preventive maintenance, patrolling and inspecting facilities, distribution substation operations and maintenance, maintain overhead electric poles. However, five out of the ten major work categories are related to PG&E's gas department. The identified major work categories include work to repair damages or failed gas facilities; customer service visits to investigate gas leaks, carbon monoxide monitoring, appliance pilot relights, adjustments, or safety checks; preventive maintenance on gas distribution assets; leak surveys on gas distribution facilities, and cathodic protection to mitigate the effects of corrosion on metallic gas distribution pipelines. PG&E should not be allowed to use VPF funds paid by electric customers to cover the cost of gas department operations and maintenance – emergent or not.

Second, Category 2 of PG&E's specifically-identified projects includes spending on PG&E's hydroelectric generation system to enhance its asset management system, perform deferred corrective maintenance, increase routine maintenance, increase operational staff, and develop more comprehensive operations and maintenance standards.[55] When asked in discovery whether PG&E intended to use VPF revenue to make improvements to its generation assets or extend their operating lives, PG&E simply responded that it planned to accelerate enhancements to the asset management, inspection, and maintenance activities associated with its utility-owned hydro generation facilities and that the activities are expected to increase the resiliency and reliability of the assets rather

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[54] *Id*., pages 9-13 to 9-15, Table 9-1.
[55] *Id*., pages 9-7 to 9-9.

than extend their lives.[56] Without additional information CalCCA is unable confirm whether VPF funds will be used in a way that increases generation output or effectively extends the life of the assets on behalf of PG&E's bundled customers. If either result occurs, PG&E's use of VPF funds would raise complex issues regarding on which customers' behalf those investments are being made. Those issues, in turn, implicate questions regarding appropriate vintaging of the assets and whether PG&E would gain a competitive advantage over other LSEs in meeting its procurement requirements on account of revenue paid by all customers. The Commission can avoid having to resolve these thorny issues by requiring PG&E to prioritize other non-generation-related projects.

PG&E's primary justification that work on its hydro system meets the Section 712.8(s)(1) priorities is that it would fall under subsection (F) Increasing resiliency and reducing operational and system risk. While there is no uniformly adopted definition of resiliency in the electric industry, I understand the term resiliency to refer to the ability to withstand or recover from disruptive events. Performing additional maintenance and increasing staff at hydroelectric facilities may reduce the frequency or duration of forced outages at those specific units, but doing so will not provide any noticeable difference to retail customers in PG&E's service territory because when a hydro unit goes on outage the lost generation is replaced through CASIO market dispatch. On the other hand, recent Commission activity related to resiliency, such as the microgrids rulemaking R.19-09-009[57] and the North Coast Resiliency Initiative,[58] has focused on delivery infrastructure

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[56] *See* Attachment B, PG&E response to CalCCA data request 1.26.

[57] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids.

[58] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids/north-coast-resiliency-initiative.

and efforts to reduce customer outages. Consistent with the principles proposed above that VPF-funded projects benefit the maximum number of customers, CalCCA recommends PG&E be required to pursue opportunities to fund projects related to resiliency on the distribution system, such as undergrounding conductor or installing microgrids, before subsidizing operation and maintenance costs at generation facilities.

Ensuring the safety, reliability, and resiliency of the electrical distribution system at a reasonable cost is an issue of growing emphasis for the Commission. On June 6, 2024, the Commission issued its Order Instituting Rulemaking to Update Rules for the Safety, Reliability, and Resiliency of Electrical Distribution Systems, stating, "Newly emergent risks and priorities motivate the Commission to reexamine several of its current oversight practices. These emergent risks and priorities include the following: (1) aging equipment; (2) extreme, climate-driven weather evens; (3) evolving wildfire mitigation practices; (4) increased prioritization of equity; and (5) increased prioritization of electrification, which is a critical building block of the State's strategic goal to decarbonize."[59] In May 2021, the Commission published a report entitled "Utility Costs and Affordability of the Grid of the Future" in which it produced a long-term rate forecast by cost category for PG&E, SCE, and SDG&E. The report states, "The need to improve the safety and reliability of the electric system while meeting California's climate goals and various statutory mandates will require careful management of rate and bill impacts to ensure that electric services remain affordable."[60] The report projected that PG&E's bundled residential rates for

[59] Order Instituting Rulemaking R.24-05-023 issued June 6, 2024, page 4.

[60] *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf (page 7).

distribution would increase by an annual growth rate of 7.9% from 2024 to 2030, compared to annual growth in transmission and generation rates of 2.9% and 3.3%, respectively.[61]

Adopting CalCCA's recommended principles helps ensure VPF funds will be spent in a way which benefits the most customers possible consistent with the VPF funding source from statewide electric customers. PG&E should be required to revise its planned uses of VPF funding in 2025 to: 1) remove any expenditures (or possible expenditures) related to its gas line of business, 2) remove expenditures on generation-related projects, and 3) update expenditures on specified projects along with a demonstration that it selected eligible projects that benefit the largest number of customers possible.

This concludes my testimony.

[61] *Id*., Appendix B, Figure 47.

Attachment A

Curriculum Vitae of Brian Dickman

BRIAN DICKMAN

Partner

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EDUCATION

Master of Business Administration, Finance Emphasis, University of Utah

Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

Cost of Service and Rates

Financial Analysis and Modeling

Power Charge Indifference Amount

Regulatory Strategy

Revenue Requirement

Mr. Brian Dickman is a partner in NewGen's energy practice with over 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility-avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison, which the California Public Utility Commission established to provide an independent review of the centralized procurement of local generation capacity requirements.

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He interfaced with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load. A sample of Mr. Dickman's utility clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, Canada
- Liberty Utilities, CA

Electric Cost of Service, Rate Design, and Regulatory Analysis (cont.)

- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

Non-Utility Clients

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirements, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing loads. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources and support of modifications to the avoided cost calculation for small resources.

BRIAN DICKMAN

Partner

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Customer Choice at a Vertically Integrated Utility
Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Record of Testimony: **Brian Dickman**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. SCE	A.23-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2023
2. PG&E	A.22-09-018	Expert testimony evaluating customer benefits of a proposal to transfer generation assets to a newly created regulated utility subsidiary	California Public Utilities Commission	California Community Choice Association	2023
3. PG&E	R.23-01-007	Expert testimony proposing new rate design and allocation of generation benefits during period of extended operations at Diablo Canyon Nuclear Power Plant	California Public Utilities Commission	California Community Choice Association	2023
4. Joint IOUs	R.22-07-005	Expert testimony addressing inclusion of stranded costs in newly proposed income graduated fixed charges for residential customers	California Public Utilities Commission	California Community Choice Association	2023
5. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
6. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
7. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022

Record of Testimony: **Brian Dickman**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022
9. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
10. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
11. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
12. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
13. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
14. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021
15. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
16. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
17. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
18. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
19. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
20. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
21. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015
22. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015
23. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
24. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
25. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
26. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
27. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
28. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015
29. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
30. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
31. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
32. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
33. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
34. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
35. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013
36. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
37. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
38. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
39. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
40. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
41. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011

Record of Testimony: **Brian Dickman**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
42. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
43. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011
44. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low-income customer weatherization rebates	Idaho Public Utilities Commission		2010
45. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
46. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
47. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
48. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
49. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

Attachment B

Select PG&E Responses to CalCCA Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_001-Q026		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q026		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Kristin Manz	Requester:	Corey Cochran

QUESTION 026

Referring to PG&E's prepared testimony, page 9-8, lines 6-33: Provide the following:

a. Does PG&E intend to use the volumetric performance fee revenue to make improvements to its generating assets (either PG&E-owned or contracted)?

b. If so, please describe which assets would be improved with this revenue, including identifying whether any of the assets are PCIA-eligible resources.

c. Does PG&E plan to make any improvements which would extend the life of any PG&E-owned or contracted generating assets? If so, please explain.

ANSWER 026

PG&E proposes to use a portion of the DCPP volumetric performance fees to accelerate enhancements to the asset management, inspection, and maintenance activities associated with its utility-owned hydro generation facilities. These activities are aimed at reducing operational and system risk. The activities are expected to increase the resiliency and reliability of the assets, rather than extend the life of the assets. PG&E's hydro facilities are PCIA-eligible resources.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_001-Q027		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q027		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 027

Referring to PG&E's prepared testimony, pages 10-4 through 10-5 and PG&E's Application at page 10: Please describe when during the true-up process interested parties will have an opportunity to review and audit actual costs and revenues from the previous year, including the accounting treatment of those costs and revenues.

ANSWER 027

D.23-12-036 Ordering Paragraph 4 generally accepted PG&E's proposed ERRA-like process to authorize forecast DCPP extended operation costs and subsequent true-up to actual costs and market revenues. Consistent with the mandate provided in Public Utilities Code Section 712.8(h)(1), the subsequent true-up process occurs via "an expedited Tier 3 advice letter process, provided that there shall be no further review of the reasonableness of costs incurred if actual costs are below 115 of the forecasts costs." Section 712.8(h)(1) and D.23-12-036 do not contemplate an audit of these costs.[1]

Pursuant to Section 712.8(h)(1), costs in excess of 15 percent above PG&E's approved annual DCPP extended operations forecast application would be subject to a reasonableness review.

[1] See Pub. Util. Code § 712.8(h)(1) as quoted above. See D.23-12-036, COL 59.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_001-Q028		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q028		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 028

Referring to PG&E's prepared testimony, pages 10-4 through 10-5 and PG&E's Application at page 10: Will interested parties have an opportunity to review and audit actual costs and revenues from the previous calendar year during a Tier 3 Advice Letter process, or will that opportunity occur as a part of a forecast proceeding? Please explain.

ANSWER 028

As part of the Tier 3 advice letter process, parties may issue discovery requests in a manner that is consistent with the Commission's best practices for discovery. However, to the extent that CalCCA assumes that the Tier 3 advice letter process adopted by the Commission mirrors the audit of recorded entries that occurs in the annual Energy Resource Recovery Account (ERRA) Compliance Review proceeding, the requirements set forth under Senate Bill 846 do not mandate a review and audit of actual costs and revenues[1] and as recognized by D.23-12-036.[2]

In response to this question, PG&E assumes opening a new CPUC action will be unnecessary as long as recorded costs do not exceed 115 percent of the adopted forecast.

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1 Please refer to PG&E's response to Question 27 of this request and Public Utilities Code Section 712.8(h)(1).

2 Please refer to PG&E's response to Question 27 of this request and D.23-12-036, COL 59.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_001-Q029		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q029		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 029

Referring to PG&E's prepared testimony, pages 10-4 through 10-5 and PG&E's Application at page 10: Does PG&E plan to provide detailed workpapers regarding its actual costs and revenues as a part of the annual true-up process?

ANSWER 029

Please refer to PG&E's responses to Questions 27 and 28 of this data request. As Section 712.8(h)(1) of the Public Utilities Code and Decision 23-12-036 do not contemplate an audit as part of the true-up process for costs that do not exceed 115 percent of the original cost forecast, PG&E intends to limit workpapers for the Tier 3 advice letter process to a summarized level. However, as also noted, amounts exceeding 115 percent of the approved DCPP cost forecast will be subject to a regulatory process.

§PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q003		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q003		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 5, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 003

Referring to PG&E's response to CalCCA DR 1.29: Please describe the regulatory process PG&E is referring to in this response which DCPP costs exceeding 115 percent of the approved forecast will be subject to.

ANSWER 003

As part of the subsequent true-up process identified in Section 712.8(h)(1), PG&E proposed that the content of the annual expedited Tier 3 DCPP Extended Operations Costs True-Up advice letter be structured similarly to the review of procurement-related balancing accounts in the annual ERRA Compliance Review proceeding.[1] Please see PG&E's response to Question 6 of this data request for more specifics. Consistent with that process, PG&E intends to present all recorded costs—including if they are above 115% of the approved forecast in the Tier 3 advice letter, as well as analysis of the drivers—and seek Commission direction as to how it plans to conduct a reasonableness review if costs exceed 115% of the approved forecast.

[1] See DCPP OIR, PG&E Testimony, Chapter 3, Page 3-12, Lines 15-28.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q005		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q005		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 5, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 005

Referring to PG&E's responses to CalCCA DR 1.27 - 1.29; Provide the following:

a. Please explain when the Tier 3 Advice Letter will be filed each year.

b. When will the first Tier 3 Advice Letter be filed?

c. Please explain how and when the true-up will be rolled into rates.

ANSWER 005

PG&E responds as follows:

a. PG&E has not yet determined the exact timing it expects to submit its expedited Tier 3 Advice Letter for the annual true-up, other than it must come after the end of the prior calendar year. PG&E is assessing the appropriate timing of this filing and how to align it with the DCPP Forecast process to include any update in rates expeditiously.

   However, as noted in PG&E's Testimony in the DCPP OIR, it currently anticipates submitting an advice letter governing the first Test Year of extended operations on or before March 31, 2026, which would provide the appropriate time for disposition of a true-up or true-down amount to be reflected in the next Fall Update.[1]

b. Please see response to subpart a.

c. For purposes of PG&E's cost recovery Application proposal, PG&E proposed that the actual expense project costs and O&M expenses that are at or below 115 percent of PG&E's forecast costs be amortized in rates on January 1 of each year (via the DCPP Forecast proceeding) subject to any final review through General Order 96-B advice letter process (in the true-up).[1]

[1] Please see PG&E's Testimony, Chapter 3, Page 3-13, Lines 13-18.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q006		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q006		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 5, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Corey Cochran

QUESTION 006

Referring to PG&E's response to CalCCA DR 1.29: Please explain further PG&E's understanding regarding the review of costs during the Tier 3 Advice Letter Process. Does PG&E anticipate review of the gross costs only, costs net of market revenue only, or something else?

ANSWER 006

As explained in response to Question 3 of this data request, PG&E proposed that the contents of the annual expedited DCPP Extended Operations Costs True-Up advice letter be structured similarly to the review of procurement-related balancing accounts in the annual ERRA Compliance Review proceeding, with disposition via a resolution of the Commission.[1]

Specifically, the presentation would: (1) describe the background and structure of the DCEOBA and the associated subaccounts, (2) describe activity recorded to the account and associated subaccounts, and (3) describe the variance analysis for PG&E's forecasted costs compared to the actual recorded costs for the record period.

PG&E believes that the presentation of the activity in the expedited Tier 3 advice letter would include all activity in the DCEOBA, but that costs would be presented gross to properly review actual project costs and O&M expenses against the forecast.

[1] See DCPP OIR, PG&E Testimony, Chapter 3, Page 3-12, Lines 15-28.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q007		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q007		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 5, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley / Conor Doyle	Requester:	Corey Cochran

QUESTION 007

Referring to PG&E's response to CalCCA DR 1.28; Provide the following regarding the DCPP forecast application filed in 2025:

a. Please explain will the DCEOBA account be strictly historical (i.e. recorded balance as of December 2024)?

b. Or will it be a projected balancing account balance (i.e. as projected by the end of December 2025)?

ANSWER 007

PG&E interprets this question to be asking whether the DCPP Forecast Application (starting in the second year) will follow the same conventions of the ERRA Forecast framework, whereby forecasted over and undercollections of the targeted balancing accounts at the end of the filing year (in this case, the 2025 DCEOBA balance) will be included in the revenue requirement request for the following year (in this case, the 2026 revenue requirement to collect in rates).

As noted in response to Question 3 of this data request, Ordering Paragraph 4 of Decision 23-12-036 generally accepted PG&E's proposed ERRA-like process to authorized forecast DCPP extended operation costs and subsequent true-up to actual costs and market revenues.

As detailed by PG&E's proposal in the DCPP OIR:

> For the purposes of PG&E's cost recovery Application proposal, PG&E proposes that actual expense project costs and O&M expenses that are at or below 115 percent of PG&E's forecast costs be amortized in rates on January 1 of each year subject to any final review through the General Order 96-B advice letter process.[1]

Essentially, PG&E expects the 2026 revenue requirements for rates to include the forecast over or undercollection in the DCEOBA to the extent that actual expenses are

[1] See DCPP OIR, PG&E Testimony, Chapter 3, Page 3-13, Lines 4-8.

at or below 115 percent of PG&E's forecast cost to be amortized in the next AET while recorded balances are still reviewed in the expedited Tier 3 true-up advice letter. This is much like projected over and undercollections in generation and procurement-related balancing accounts are presented in the ERRA Forecast today and still later reviewed in the ERRA Compliance proceeding; however, the key differences is amortizations included in the forecast will not exceed the 115 percent threshold.

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q012		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q012		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 12, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Thomas R Baldwin	Requester:	Corey Cochran

QUESTION 012

Referring to PG&E's prepared testimony page 7-7, line 28, through page 7-8, line 17: Please provide a list of each unplanned outage experienced at DCPP unit 1 or unit 2 over the last 10 years. For each outage, please provide the following:

a. Generating unit
b. Outage start date
c. Outage end date
d. Lost generation output (MWh)
e. Lost capacity (MW-month)
f. Replacement power costs
g. Description of the outage event, including root cause
h. Whether the Commission determined that the unit was out of service as a result of a failure of the operator to meet the reasonable manager standard.

ANSWER 012

PG&E objects to this request on the grounds that CalCCA's request is overly broad and outside the scope of the proceeding. Subject to and notwithstanding this objection, PG&E responds as follows. See Attachment 1 to this data response (see Excel, filename "DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q012Atch01.xlsx").

Generating Unit	Outage Start Date	Outage End Date	Lost Generation Output (MWh)	Lost Capacity (MW-Month)*	Replacement Power Cost	Description of the outage event including root cause	Did the Commission determine that the unit was out of service as a result of a failure of the operator to meet the reasonable manager standard?
1	6/25/13 22:37	7/2/13 14:17	178,348	244	$9,703,491	Socket weld failure from high cycle fatigue requiring unit shutdown to repair.	No
2	7/10/13 9:50	7/14/13 1:42	97,796	134	$4,739,812	Lightning arrestor insulator arc resulting in unit trip during hot wash due to asymmetric contamination deposition from environment	No
1	3/16/14 20:20	3/27/14 3:22	275,936	378	$12,156,562	Reactor coolant pump 1-3 high seal leak-off flow due to pump shaft misalignment to seal requiring unit shutdown to repair.	No
2	2/2/14 11:29	2/8/14 3:37	151,516	208	$10,689,742	Lightning Arrestor insulator arc resulted in unit trip during light rain due to asymmetric contamination deposition from environment	No
2	8/14/14 23:30	8/18/14 17:34	100,244	137	$4,398,820	Manufacturer supplied diesel bolt broke due to high cycle fatigue while a second diesel was out of service for maintenance, thereby requiring unit shutdown per operating license. Manufacturer instructions did not provide adequate detail to preclude such failure.	No
1	1/2/15 20:00	1/4/15 20:11	53,821	74	$1,797,741	Residual heat removal pipe weld failed due to vibration induced by containment fan cooler operation, extending an unrelated planned maintenance outage by two days to perform repairs.	No
2	12/1/18 10:06	12/3/18 17:57	62,161	85	$1,836,765	California transmission grid event triggered a DCPP switchyard protective scheme which caused the unit to disconnect from the grid.	No
2	2/13/20 15:18	2/16/20 6:20	70,119	96	$1,439,827	Control rod misalignment during testing due to original construction wire lug crimp deficiency failing after decades of operation, thereby requiring unit shutdown per operating license.	No
2	7/17/20 13:46	8/2/20 12:25	425,889	583	$12,276,673	Generator cooling system high cycle fatigue failure requiring unit shutdown to repair.	Event addressed in 2021 ERRA compliance proceeding (A.22-02-025). No decision in this proceeding has been issued.
2	10/15/20 3:44	11/26/20 13:31	1,132,793	1,552	$49,326,713	Other generator high cycle fatigue failures requiring unit shutdown to repair.	Event addressed in 2021 ERRA compliance proceeding (A.22-02-025). No decision in this proceeding has been issued.
2	12/2/20 13:17	1/12/21 17:44	1,100,145	1,507	$41,932,354	Other generator high cycle fatigue failures requiring unit shutdown to repair.	Event addressed in 2021 ERRA compliance proceeding (A.22-02-025). No decision in this proceeding has been issued.
2	4/19/21 15:09	4/25/21 5:23	149,402	205	$3,754,147	Contractor error in reconnection of generator cooling hoses requiring unit shutdown to correct.	Event addressed in 2021 ERRA compliance proceeding (A.22-02-025). No decision in this proceeding has been issued.
2	10/15/21 17:49	11/3/21 5:01	493,282	676	$28,070,513	Feedwater heater tube leak from first in industry failure mechanism required unit shutdown to repair.	Event addressed in 2021 ERRA compliance proceeding (A.22-02-025). No decision in this proceeding has been issued.
1	4/23/22 0:03	4/26/22 17:36	100,027	137	$4,009,040	Blowdown system pressure control system failed resulting in condenser air in-leakage requiring unit shutdown to repair.	Event addressed in 2022 ERRA compliance proceeding (A.23-02-018). No decision in this proceeding has been issued.
2	5/24/24 2:33	5/25/24 9:55	35,037	48	$442,392	Steam line gasket leak during power ascension after refueling outage 2R24. Cause is under evaluation.	This event will be addressed in the 2024 ERRA compliance proceeding to be filed in February 2025.

Basis of Lost Generation:
Lost generation provided is the maximum dependable capacity of the unit multiplied by the hours the unit was offline.

Basis of Lost Capacity:
MW-Month is not an industry recognized term for lost capacity; the value provided in the table is the total MW generation lost for a given outage divided by the hours in a normalized month (i.e. Lost generation output / (30.42 days/month x 24 hrs/day)).

Basis of Replacement Power Cost:
Above listed replacement power costs were determined using the Joint Stipulation Regarding Replacement Cost of Energy between the Office of Ratepayer Advocates and Pacific Gas and Electric Company, Dated September 4, 2014. Refer to 2013 ERRA compliance proceeding (A.14-02-008).
Rows 2 and 3 were based on the 2013 ERRA compliance proceeding (A.14-02-008) Decision 18-05-025 dated May 31, 2018, pages 28 and 33 respectively
Row 5 was previously provided in response to Office of Rate Payer Advocates Data Request 002 Question 005 in 2014 ERRA Compliance Proceeding (A15-02-023)
Row 9 was previously provided in response to Joint CCAs Data Request 002 Question 47 in the 2020 ERRA Compliance Proceeding (A21-03-008)
Row 10 -14 were previously provided in response to Alliance for Nuclear Responsibility (A4NR) Data Request 002 Question 003 in the 2021 ERRA Compliance Proceeding (A22-02-015)
Row 15 was previously provided in response to Cal CCA Data Request 002 Question 007 in the 2022 ERRA Compliance Proceeding (A23-02-018)
Note Row 16 was based on analysis with data available at time of data request (estimate subject to change, e.g., pending possible updates to CAISO final settlement values).

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response

PG&E Data Request No.:	CalCCA_002-Q013		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_002-Q013		
Request Date:	June 19, 2024	Requester DR No.:	002
Date Sent:	July 5, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Thomas R. Baldwin	Requester:	Corey Cochran

QUESTION 013

Referring to PG&E's prepared testimony page 7-7, line 28, through page 7-8, line 17: Has the Commission ever determined that an unplanned outage of a DCPP unit was due to failure of the operator to meet the reasonable manager standard. If yes, please explain in detail.

ANSWER 013

PG&E objects to this request on the grounds that CalCCA's request is outside the scope of the proceeding. Subject to and notwithstanding this objection, PG&E responds as follows:

To respond to this question, PG&E reviewed the Energy Resource Recovery Account (ERRA) compliance proceedings back to 2010. In that review, PG&E has identified one such occurrence, which was with respect to a DCPP Unit 2 outage on October 11, 2012 that occurred due to a flashover on the "A" phase Coupling Capacitor Voltage Transformer. The event was presented in Application 13-02-023 and is discussed in detail in Section 9 of Decision 16-04-006.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

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July 29, 2024

Attorney for the
Joint Community Choice Aggregators and
City and County of San Francisco

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I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC or "Commission") *Administrative Law Judge's Ruling Directing Responses to Questions Regarding Implementation of Decision 24-05-065* dated June 5, 2024 ("ALJ Ruling" or "Ruling"), Ava Community Energy ("Ava"), Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Reply Comments.

The Joint CCAs are encouraged by the robust participation of a variety of stakeholders in the development of the implementation details of the Community Renewable Energy ("CRE")

Program as adopted in Decision ("D.") 24-05-065 ("the Decision"). At the same time, the variation in the many proposals regarding the structure of the tariffs, developer compensation, and customer incentives may be difficult to reconcile into a single proposal. As a threshold matter, the Joint CCAs would like to highlight that California already has a well-functioning community solar program, the Disadvantaged Communities ("DAC") Green Tariff ("DAC-GT") program. The Joint CCAs strongly recommend that the new CRE Program be modeled after the existing DAC-GT program to ensure consistency across community solar programs in California and to achieve significant administrative efficiencies considering the limited program funding. The following Reply Comments are submitted with this goal in mind and focus on three core topic areas: (1) CCA participation under the CRE Program; (2) developer compensation; and (3) customer enrollment and bill credit.

II. REPLY

A. CCA PARTICIPATION

i. Assembly Bill 2316 and the Decision Authorize CCAs and IOUs to Administer CRE Programs on Behalf of Their Customers

The Commission should disregard comments by Southern California Edison Company ("SCE") stating that the CRE Program should be administered by the Investor Owned Utilities ("IOUs") on behalf of all customers including bundled, community choice aggregator ("CCA") and direct access customers.[1] SCE argues that CCAs cannot contract for, and administer, CRE projects under the CRE Foundational Tariffs. SCE further argues that because CCA participation would be voluntary, allowing a CCA's tariff to serve as a Foundational Tariff for the CRE Program would not ensure all CCA customers can participate.[2]

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[1] Opening Comments of Southern California Edison Company on ALJ Ruling ("SCE Opening Comments") at 10.

[2] SCE Opening Comments at 22.

Assembly Bill ("AB") 2316 makes clear that CCAs and electric service providers ("ESPs") may participate in any new community renewable energy program established by the Commission.[3] Additionally, the Decision explicitly states that "CCAs are permitted to participate in the new community renewable energy program" and, as such, "the foundational tariffs will need to be revised to accommodate this participation."[4] The Decision further confirmed that a future ruling on the details of the CRE Program would include questions around the process for CCA participation in the program, as well as which CCA tariffs would be eligible for the program.[5] These provisions clearly outline that CCAs are permitted to participate in the CRE Program if they decide to do so. As such, it is not relevant whether CCAs may currently offer the Foundational Tariffs, as the Decision is clear that the Foundational Tariffs must be revised to ensure CCA participation.

In addition to being contrary to statute and the Decision, SCE's proposal is not in line with the other IOUs' proposals. San Diego Gas & Electric Company ("SDG&E"), for example, is opposed to serving unbundled customers in SDG&E's service territory, further stating that SDG&E supports CCAs "being able to offer whatever choices and programs to customers that they would like to; expanding customer choice."[6] SDG&E further states that CCAs should have the authority to market the CRE Program directly to their customers without creating confusion.[7] Pacific Gas & Electric Company ("PG&E") also supports CCAs offering the CRE Program to

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[3] *See* Pub. Util. Code Section 769.3(b)(2)(B).
[4] D.24-05-065 at 148.
[5] *Id*. at 151.
[6] Comments of San Diego Gas & Electric Company Per ALJ Ruling ("SDG&E Opening Comments") at 4.
[7] SDG&E Opening Comments at 3-4.

their customers.[8] Many parties agree.[9] Pursuant to AB 2316 and the Decision, a CCA must be able to administer the CRE Program on behalf of their own customers if they elect to do so.

ii. Program Funding Should be Allocated to Participating Load Serving Entities Based on Load Share

As noted in parties' Opening Comments, the program capacity for the CRE Program is implicitly limited due to the public funding available for the program.[10] While the Decision doesn't establish an explicit program cap for the CRE Program, as noted in Opening Comments, the Joint CCAs calculate that the allocated funding amount will effectively limit the CRE Program to around 50 MW.[11] Taking into account the limited funding, and therefore, limited program capacity, the Commission should determine a methodology for allocating either the available funding or capacity to the participating load serving entities ("LSEs") administering the CRE Program. While many parties in Opening Comments focused on the allocation of funds among customers and developers in response to the ALJ Ruling, it is equally important to consider the allocation of funds among each LSE, or program administer.[12] In general, the Joint CCAs support Opening Comments stating that participating LSEs should be allocated a

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8 Opening Comments of Pacific Gas and Electric Company in Response to ALJ Ruling ("PG&E Opening Comments") at 17.

9 *See* Comments of Dimension Renewable Energy on ALJ Ruling ("Dimension Opening Comments") at 25 ("CCAs have the ability to develop their own wholesale energy contracts and tariffs for enabling this program"); Comments of the Solar Energy Industries Association on the Implementation of D.24-05-065 ("SEIA Opening Comments") at 23 ("CCAs should have full authority to manage their own CREP procurement and the disbursement of their share of incentive funds to projects and subscribers"); Clean Coalition Comments on ALJ Ruling ("Clean Coalition Opening Comments") at 10 ("CCAs should have the flexibility to develop FITs with additional compensation beyond what is provided in ReMAT or the SOC").

10 SCE Opening Comments at 4 ("Given the current funding that is available, the CRE program should organically start smaller than it may potentially be as more funding materializes…"); *see also* SEIA Opening Comments at 18-19.

11 Opening Comments of the Joint CCAs on ALJ Ruling ("Joint CCA Opening Comments") at 6.

12 *See* ALJ Ruling at 4-5, Question 4.

proportional share of non-rate payer funding based on their respective load shares within the state.[13]

Specifically, the Joint CCAs propose (1) that available program funding for the CRE Program be allocated among the participating LSEs, and (2) that the funding be split between participating LSEs based on load share following the process described below. First, the Joint CCAs believe that as the program funding is the limiting factor for the CRE Program, allocating the funding, rather than capacity, provides a simpler approach than calculating a capacity cap based on the available funding and, in turn, allocating that capacity among the LSEs. Second, the Joint CCAs believe the load share approach is a reasonable and fair methodology for allocating program funding as this method encourages appropriate resource distribution based on the demand each LSE serves.[14]

Further, as mentioned above in Section II.A.i., CCAs and ESPs are permitted to participate in the CRE Program if they elect to. It is important to note that this includes all CCAs and ESPs, not just those CCAs currently administering a DAC-GT program. Under the Joint CCAs' proposal in Opening Comments, and as is consistent with AB 2316, CCAs [and ESPs] would have 180 days upon the issuance of a second decision in this proceeding to submit their own CRE Program tariffs through a Tier 2 Advice Letter, thereby notifying the Commission of the intent to participate in the CRE Program.[15] Once all LSEs have indicated their interest in offering the CRE Program, available public funding would then be split among participating LSEs based on each LSEs' load share.

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13 *See* Dimension Opening Comments at 7; Valta Energy Comments on ALJ Ruling ("Valta Opening Comments") at 1; SEIA Opening Comments at 23.

14 *See* Valta Opening Comments at 1.

15 *See* Pub. Util. Code § 769.3(b)(2)(B); *see also* Joint CCAs Opening Comments at 22.

B. DEVELOPER COMPENSATION

i. Foundational Tariffs Must be Updated to Include Energy Storage

Many parties highlight in Opening Comments the importance of incorporating energy storage under the CRE program and provide a variety of proposals of how energy storage should be compensated under the program.[16] The Joint CCAs would like to take this opportunity to further elaborate on their proposal made in Opening Comments regarding the treatment of energy storage under the CRE Program. The Joint CCAs believe that the Decision gives the Commission the authority to update the existing Foundational Tariffs to align them with the rules and requirements of the CRE Program, including the inclusion of solar + storage projects.[17] The Joint CCAs propose that there be two "CRE Program Tariffs" created by each LSE offering the CRE Program – one CRE Program tariff offering standard pricing for solar only resources ($/kWh for energy produced) and one CRE Program tariff offering standard pricing for solar + storage resources ($/kWh for energy produced by solar system *and* $/kW-month for the capacity provided by the storage system). The Commission would set the pricing/developer compensation under both CRE Program Tariffs, i.e. the Commission would also establish the "base payment" for the energy storage resource for co-located solar + storage systems. For solar + storage systems, both the base energy and capacity payments (if the project has deliverability) would be paid by ratepayers as they reflect costs that the LSEs incur if they were to procure solar + storage resources outside of the CRE Program. Only adders to the developer compensation that go above

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[16] *See* D.24-05-065 at 169, OP 1(i) ("Storage – The community renewable energy program tariff shall allow for co-located solar and storage."); *see also* Valta Opening Comments; Dimension Opening Comments; SEIA Opening Comments; Cypress Creek Opening Comments; Cal Advocates Opening Comments; CCSA Opening Comments.

[17] *See generally id*. at 169, OP 1 (describing the adopted elements of a community renewable energy program).

and beyond the usual procurement costs (a concept called "above market generation costs" under the DAC-GT program) would be recovered by CRE Funding.[18]

ii. The Commission Should Facilitate a Working Group to Establish a Methodology for Developer Compensation Beyond the Base Payments Provided by the Foundational Tariffs

The majority of parties highlight in Opening Comments that additional "adders" must be provided beyond the base payment provided by the Foundational Tariffs to allow for local, distributed project development under the CRE Program.[19] However, there is currently no alignment on the methodology that should be used to establish the level of those adders. Opening Comments include a range of proposals for calculating the adders including, for example, proposals based on the Cost of Renewable Energy Spreadsheet Tool ("CREST") model,[20] a reverse auction mechanism,[21] a set adder of 5%,[22] a comparison to DAC-GT procurement costs,[23] or a "missing money" revenue requirement calculation.[24] The Joint CCAs support the further exploration of the proposed methodologies and suggest the Commission give parties the opportunity to present their proposals in more detail in working group sessions. Based on the discussions in the working group sessions, the Commission and parties may decide on the most

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[18] "CRE Funding" refers to the funding set aside in the Decision for the CRE Program including the $33 million appropriated to the Commission by AB 102 for community energy renewable program usage and storage-backed renewable generation programs, as well as the Environmental Protection Agency's ("EPA") Solar for All grant funding.

[19] *See e.g.*, Opening Comments of the Joint CCAs; Opening Comments of the Coalition for Community Solar Access on ALJ Ruling ("CCSA Opening Comments"); Opening Comments of The Utility Reform Networks on the ALJ Ruling ("TURN Opening Comments") at 5; Opening Comments of the Public Advocates Office on ALJ Ruling ("Cal Advocates Opening Comments") at 10; SCE Opening Comments; PG&E Opening Comments.

[20] CCSA Opening Comments at 30.

[21] TURN Opening Comments at 5; Cal Advocates Opening Comments at 10.

[22] SCE Opening Comments at 3.

[23] PG&E Opening Comments at 12.

[24] SEIA Opening Comments at 8.

appropriate valuation methodology to establish the "adders" provided to developers under the CRE Program.

iii. Upfront Payments to Developers Would Require Established Guardrails to Ensure Proper Use of Funds

Several industry representatives propose that a portion of the developer compensation should be paid "upfront," presumably once a project has reached its Commercial Operation Date ("COD").[25] The Joint CCAs have concerns about this proposal and recommend that, if such a proposal were to be adopted, specific guardrails must be established to ensure the funds are appropriately used.

Providing upfront payments to developers poses risks to an LSE as payments are made in advance of the delivery of services under the contract. There could be performance issues with the project throughout the duration of the contract term that could prove challenging to address if payments had already been made. Additionally, stakeholders reference incentive programs for behind-the-meter ("BTM") resources as examples for upfront incentives (such as the California Solar Initiative ("CSI")).[26] This is not a direct comparison as those solar projects operate on a much smaller scale. With significantly larger project sizes under the CRE Program come increased costs, and therefore, increased potential risk when providing upfront incentives and an increased need to protect against those risks.

The risks and challenges mentioned above, absent proper guardrails, could result in long and cumbersome legal processes to claw back already paid upfront incentives from developers for non-performance under a project, or otherwise risk depletion of CRE Funding without CRE Projects performing as projected. Any claw back provisions or other methodologies in the event

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[25] *See e.g.* CCSA Opening Comments at 30; SEIA Opening Comments at 18; Dimension Opening Comments at 9-10; Clean Coalition Opening Comments at 4-5; Valta Opening Comments at 2-3.

[26] Dimension Opening Comments at 10.

of delay or non-performance under a project should therefore be carefully vetted and determined through parties in this proceeding if the Commission were to consider adoption of this proposal. For example, any upfront incentives that are clawed back from a developer, such as in the scenario described above, should be returned to the LSE administering the CRE Program.

The Joint CCAs acknowledge the challenge provided by the Solar for All programs' five-year performance period. However, when looking more closely into the language in the Environmental Protection Agency's ("EPA") Request for Applications ("RFA") for the Solar for All Program (EPA-R-HQ-SFA-23-01), EPA notes that "[a]ll activities funded with the initial grant award must be completed within the negotiated program performance period of up to five years, meaning **all program grant funds must be deployed** [emphasis added] as described in the application."[27] The Joint CCAs note that there could be a variety of definitions for the "deployment" of grant funds. For example, one could argue that grant funds are "deployed" if they are set aside for a particular solar (or solar + storage resource) for its entire performance term (e.g. 20 years). More specifically, an LSE could forecast the payments to the developer paid by Solar for All funding upon COD of the resource as established in the power purchase agreement terms and/or the CRE Program tariffs. This funding could then essentially be "set aside" for the project in the utilities' balancing accounts and would be paid out to the developer per the standard contract terms. Such a process could possibly fulfill the requirement of the EPA to "deploy" the grant funds within 5 years. The Joint CCAs are hopeful that the California Energy Commission ("CEC") (the implementing agency of Solar for All funding in California) can work with the EPA to find a workable solution for community solar in California.

[27] *See* EPA Solar for All RFA at 26, available at https://www.grants.gov/search-results-detail/348957

C. CUSTOMER ENROLLMENT AND BILL CREDIT

i. Program Administrators Should Enroll All CRE Program Participants

CRE Program enrollment of eligible customers should only be the responsibility of the LSEs administering the program. In Opening Comments, Dimension proposes that projects would be responsible for subscribing up to 25% of the subscribers in that project while the LSE would be responsible for the other 75%.[28] Dimension provides that "a division of labor for customer acquisition and management between the solar + storage project and the utility best balances the goals of [Solar for All], the non-energy benefits of community solar (such as community engagement and workforce development), and the limited funding available to support customer savings."[29] However, this approach would likely create confusion and unnecessary administrative burdens. It is simpler and more cost-effective for LSEs to be responsible for all customer enrollment under the CRE Program as proposed by the Joint CCAs, as well as other parties, in Opening Comments.[30]

Additionally, TURN proposes a statewide third-party administrator to manage enrollment and provide customer-facing information about the CRE Program. TURN argues that this "would provide a uniform engagement and education experience for customers of different [LSEs]" and that there "are likely efficiencies with using a single entity for this task rather than spreading it across multiple utilities and CCAs."[31] The Joint CCAs fundamentally disagree with the recommendation to impose a third-party administrator to manage any CRE Program enrollment or promotion of the program. As the Joint CCAs have noted multiple times throughout this

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[28] Dimension Opening Comments at 5-6.
[29] *Id*. at 5.
[30] *See* Joint CCAs Opening Comments; *see also* SCE Opening Comments at 26-27.
[31] TURN Opening Comments at 16.

proceeding, a centralized marketing entity would not be able to effectively serve the local communities like CCA program administrators can.[32] In fact, providing a "uniform" engagement and education experience, as suggested by TURN, would severely limit a main benefit of CCA participation in the CRE Program, namely, the ability of CCAs to adapt the CRE Program to the needs of their local communities.

ii. CRE Program Bill Credits Should be Provided to Low-Income Customers Only

Multiple parties advocate for bill credits being provided to only low-income customers for various reasons, including limited funding.[33] However, PG&E proposes to provide bill credits to low-income customers, as well as Title 24 customers. PG&E suggests that this is appropriate given "the statutory focus of AB 2316 on both low-income customers and consistency with Title 24."[34] While the Joint CCAs agree that there should be a focus under the CRE Program on the *enrollment* of customers looking to fulfill Title 24 compliance, the Joint CCAs do not believe that it is appropriate to give *bill credits* to Title 24 customers. The Joint CCAs do not believe that consistency with Title 24, as required by AB 2316, requires a bill credit for Title 24 customers.[35] However, under the Joint CCAs' proposal as outlined in Opening Comments,[36] non-low-income customers participating in the CRE Program and seeking Title 24 compliance could achieve Title 24 compliance at no additional cost. This, in and of itself, is a substantial benefit and incentive in

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[32] *See e.g.* Exhibit JCCA-02: Prepared Rebuttal Testimony on Behalf of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Rebuttal Testimony")

[33] *See* CCSA Opening Comments at 35 ("CCSA does not recommend the Commission establish a minimum bill savings for non-low-income subscribers"); SCE Opening Comments at 4 (proposing that the CRE program should use the external funding to provide bill credits only to low-income subscribers).

[34] PG&E Opening Comments at 2.

[35] *See* Pub. Util. Code Section 769.3(c)(1) (stating that a new community renewable energy program must be complementary to, and consistent with the requirements of Title 24 with consultation of the California Energy Commission).

[36] Joint CCAs Opening Comments at 17.

pursuing and achieving Title 24 compliance. Furthermore, the Joint CCAs support providing the maximum amount of bill support possible for low-income customers given the limited funding under the CRE Program.[37]

Finally, the CRE Funding currently available for the program is limited to funding bill credits for low-income customers and those located in disadvantaged communities only; namely the Solar for All funding is limited to low-income and disadvantaged communities[38] and the $33 million appropriated to the Commission are intended to "support disadvantaged community renewable generation and storage-backed renewable generation programs."[39] For all of these reasons, the Joint CCA recommend that bill credits should only be provided to low-income customers under the CRE Program.

iii. The "Revenue Share" for Low-Income Customers Should be Set as a 20% Discount off of the Electric Bill

In Opening Comments, the Joint CCAs supported SCE's proposal to provide low-income subscribers with an incentive based on 20% of the power purchase agreement price provided under the specific CRE project that the customer subscribes to in an effort to approximate the interest of the Commission to enable a "project revenue share" for subscribing customers.[40] However, upon further review of the Solar for All funding requirements, the Joint CCAs believe that low-income customers must be offered a minimum 20% discount off of their bill for the CRE program to be eligible for Solar for All funding ("Delivering a minimum of 20% household savings....; household savings is defined as 20% of the average household electricity bill in the

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[37] *See* Joint CCA Opening Comments at 8-9 (describing the funding limitations of the CRE Program).

[38] *See* EPA Solar for All RFA at 26, available at https://www.grants.gov/search-results-detail/348957.

[39] AB 102, Budget Act of 2023, Section 244.

[40] *See* Joint CCA Opening Comments at 15.

utility territory").[41] The CEC, as the implementing agency of the Solar for All funding in California, should discuss with EPA if this could be interpreted as a 20% bill discount of a specific customers' otherwise applicable tariff (instead of the average) as is customary under the DAC-GT program. If this were to be feasible, the implementation of the bill discount under the CRE Program would be significantly streamlined and implementation costs would be significantly reduced, as it would simply follow the existing bill discount methodology under the DAC-GT programs. It would also provide more equality between low-income customers participating in the various community solar programs in California.

III. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

July 29, 2024

Respectfully Submitted,

/s/ Brittany Iles

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City and County of San Francisco

[41] *See* EPA Solar for All RFA at 12, available at https://www.grants.gov/search-results-detail/348957.

July 29, 2024

VIA ELECTRONIC MAIL: (edtariffunit@cpuc.ca.gov)

Public Utilities Commission of the State of California
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Advice Letter 15-E **Apple Valley Choice Energy**	**Advice Letter 48-E** **Ava Community Energy**	**Advice Letter 41-E** **Central Coast Community Energy**
Advice Letter 9-E **Clean Energy Alliance**	**Advice Letter 27-E** **Clean Power Alliance**	**Advice Letter 29-E** **CleanPowerSF**
Advice Letter 10-E **Desert Community Energy**	**Advice Letter 6-E** **Energy For Palmdale's Independent Choice**	**Advice Letter 28-E** **Lancaster Energy**
Advice Letter 78-E **Marin Clean Energy**	**Advice Letter 9-E** **Orange County Power Authority**	**Advice Letter 34-E** **Peninsula Clean Energy**
Advice Letter 23-E **Pico Rivera Innovative Municipal Energy**	**Advice Letter 19-E** **Pioneer Community Energy**	**Advice Letter 10-E** **Pomona Choice Energy**
Advice Letter 13-E **Rancho Mirage Energy Authority**	**Advice Letter 21-E** **Redwood Coast Energy Authority**	**Advice Letter 20-E** **San Diego Community Power**
Advice Letter 21-E **San Jacinto Power**	**Advice Letter 35-E** **San José Clean Energy**	**Advice Letter 6-E** **Santa Barbara Clean Energy**
Advice Letter 32-E **Silicon Valley Clean Energy**	**Advice Letter 23-E** **Sonoma Clean Power**	**Advice Letter 18-E** **Valley Clean Energy**

RE: CALCCA'S REPLY TO JOINT UTILITIES' PROTEST TO APPLE VALLEY CHOICE ENERGY ADVICE LETTER 15-E, *ET AL*. (CONSOLIDATED) SUBMITTED BY CALCCA ON BEHALF OF THE JOINT CCAS TO AID IN THE IMPLEMENTATION OF COMMUNITY CHOICE AGGREGATOR FINANCIAL MONITORING AND REPORTING REQUIREMENTS ADOPTED IN DECISION 24-04-009

California Community Choice Association (CalCCA) submits this Reply to the protest of San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E) (together, the Joint Utilities), dated July 22, 2024, to the Tier 2 Advice Letter (Advice Letter) submitted by CalCCA, on behalf of Apple

Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy[1] (collectively, the Joint CCAs). This Advice Letter seeks to aid Energy Division staff in the implementation of Ordering Paragraph 7 of Decision (D.) 24-04-009[2] as well as provide clarity to the Joint CCAs on required reporting triggers.

The Joint Utilities' protest asks the California Public Utilities Commission (Commission) to reject the Joint CCAs' Advice Letter entirely, stating, "(i) it is procedurally improper because the Joint CCAs have not been authorized to seek the relief requested through the advice letter process; (ii) the relief requested in the Consolidated AL cannot be granted since the Proposed Guidelines violate the POLR Decision; and (iii) the Consolidated AL is an improper collateral attack on the POLR Decision."[3]

In this Reply, and the revised Financial Monitoring Guidance Document, the Joint CCAs correct two unintended errors in the original Financial Monitoring Guidance Document regarding the calculation of cash reserves and confidentiality. It also explains why the Commission should not adopt the Joint Utilities' recommendation to reject the Joint CCAs' Advice Letter in full, given (1) the Decision's intent is not explicit in some areas, and (2) the clarity and consistency in how CCAs monitor Tier 2 triggers through the Financial Monitoring Guidance Document does not violate the POLR Decision or its intent.

I. THE JOINT CCAS ADOPT MODIFICATIONS TO THE FINANCIAL MONITORING GUIDANCE DOCUMENT TO CORRECT UNINTENTIONAL ERRORS

The intent of the Joint CCAs' Financial Monitoring Guidance Document is to provide clarity where the Decision left room for interpretation, ***not*** to make changes to the Decision. Adoption of the revised Financial Monitoring Guidance Document would not change the fact that the Joint CCAs are obligated to fully comply with the Decision as adopted.

The Joint Utilities' protest identified inadvertent errors in the Financial Monitoring Guidance Document that the Joint CCAs agree require modification to ensure consistency with the Decision language. These modifications are documented in the clean and redlined version

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[1] The Joint CCAs have provided CalCCA with authority to submit this Advice Letter on their behalf.

[2] D.24-04-009, *Decision Implementing Senate Bill 520 Regarding Standards for Provider of Last Resort*, R.21-03-011 (Apr. 18, 2024) (the Decision or, the POLR Decision): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M529/K986/529986322.PDF.

[3] Joint Utilities' protest at 3, footnotes omitted.

(Attachment A and Attachment B, respectively) of the revised Financial Monitoring Guidance Document attached to this Reply, and described here:

- Modifies the Cash Reserves explanation from "It **should** not consider a city's general fund cash reserves" to "It **shall** not consider a city's general fund cash reserves."
- Removes all references to confidentiality in all places except section 4. The use of "confidential" in other sections reflects outdated language and has been removed.
- Modified Section 4 to ensure it directly reflects the Decision language.

The Commission should adopt the revised Financial Monitoring Guidance Document attached to this Reply. The revisions are intended to make it consistent with the already clear Decision language. The rest of the document informs elements of the Decision that are ambiguous.

II. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES' PROCEDURAL ARGUMENTS THAT THE JOINT CCAS ARE NOT AUTHORIZED MAKE ITS RECOMMENDATIONS IN THE ADVICE LETTER

The Joint Utilities make several procedural arguments in attempts to support their recommendation to reject the Joint CCAs' Advice Letter in full. First, the Joint Utilities state, "[t]he POLR Decision did not direct or authorize the CCAs to submit an advice letter to implement the financial reporting rules established in the decision, nor is such an action necessary."[4] CalCCA contacted Energy Division staff to discuss the lack of clarity that the final decision contained. CCAs would need clarity on these items to ensure that they are able to take correct action given that the Decision contains significant new requirements as well as the potential for financial penalties for failing to report as required. The Advice Letter was filed to provide such clarity after consultation with Energy Division staff. CalCCA worked with Energy Division staff on how they could implement these clarifications and through consultation, it was clear that an advice letter was the preferred venue for these clarifications.

Second, the Joint Utilities suggest that "…the advice letter process is not the proper vehicle for challenging the POLR Decision" and that the Joint CCAs' Advice Letter represents a "collateral attack" on the Provider of Last Resort (POLR) Decision.[5] The Joint CCAs' Advice Letter does not challenge the POLR Decision. The volume and intricate detail of new requirements will benefit from clarification so that CCAs can effectively comply with the order. If the Energy Division staff believes these clarifications would change the final POLR Decision, it will inform the Joint CCAs through this process.

III. THE COMMISSION SHOULD ADOPT THE REVISED FINANCIAL MONITORING GUIDANCE DOCUMENT TO MAKE CLEAR AREAS OF THE DECISION THAT WERE NOT EXPLICIT

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[4] Joint Utilities' protest at 8.

[5] *Id.* at 8-9.

The Joint Utilities took issue with two specific clarifications that CalCCA requested in its Advice Letter. First, the Joint Utilities objected to clarifying that a letter of credit was not the only credit instrument acceptable in calculating Days Liquidity on Hand (DLOH).[6] Second, the Joint Utilities find it unacceptable to allow a CCA reasonable opportunity to perform typical monthly financial reviews, accept the financial statement, and then report if necessary.[7]

The Joint Utilities interpret the Decision as strictly defining DLOH. However, the concept of DLOH is used worldwide for many reasons. It is designed to demonstrate how long an entity can continue paying its obligations given its access to cash, investments, and financial instruments at its disposal. In doing so, limiting the financial instruments to one specific instrument, such as a letter of credit (LOC), is unnecessarily limiting and was not the intent of the Commission. In fact, the Commission has recognized that CCAs have access to other instruments, allowing a LOC *and* a surety bond to satisfy a financial security requirement.[8] Further, the Joint Utilities' claim that a credit agreement "does not represent a flexible or readily available source of liquidity that can be used for general operational needs"[9] is false. Credit agreements are flexible and can be used as a source of liquidity for operational and working capital needs. Credit agreements and other lines of credit are simply other instruments that can provide liquidity.

In recognizing that there is more than one instrument, the use of a LOC in the Decision should not be construed as limiting the financial instruments that may be used as that should not have been the intent of the Decision. CalCCA added "credit agreements" to clearly reflect how the calculation would be performed in order to comply with the intent of the calculation for this purpose as well as the standard used worldwide.

The Joint Utilities also claim that the Financial Monitoring Guidance Document would extend the compliance period beyond what is contemplated in the POLR Decision with respect to noticing the Energy Division regarding Tier 2 triggers that require calculations using financial data.[10] This claim is false. Four of the Tier 2 triggers – a drop in credit rating below investment grade, defaulting on a resource adequacy procurement contract, defaulting to the California Independent System Operator Corporation's scheduling coordinator, or filing for bankruptcy – are discrete events that are easily identifiable. However, the DLOH, Debt Service Coverage ratio, and cash reserves assessments require calculations that rely on financial data that do not become available until the end of a given reporting period and are then reviewed as part of unaudited financial statements for the reporting period. CalCCA discussed this topic with Energy Division staff and concluded that the Commission did not intend to create a monitoring burden that is not feasible or practical. In fact, the Joint Utilities' example where they selected the trigger event occurring on July 5th is impractical given the calculation of the condition could only

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6 Joint Utilities' protest at 4.

7 *Id.* at 6-7.

8 The Decision at Conclusions of Law 30.

9 Joint Utilities' protest at 4.

10 The Tier 2 triggers that require calculations using financial data include: (i) DLOH is less than 45 days and Adjusted Debt Service Coverage Ratio is less than 1.0; and (ii) cash reserves for the CCA fall below 5% of annual expenses.

occur after the financial data becomes available at the end of a given reporting period, like the end of the month.

The Joint Utilities' example also shows why "days" should mean "business days." The example the Joint Utilities provide would be the day after a holiday and demonstrates why "days" not meaning "business days" is unreasonable. Taken to an extreme, had the trigger happened the day before Thanksgiving Day, the next four days would be consumed by a holiday and weekend. This would then leave only six days (with the last being the following weekend) for the CCA to validate that the trigger had been hit and to file the necessary letter. Also, the Joint Utilities' description of when Energy Division would request a meeting[11] does not make sense, as it would follow that Energy Division would request the meeting after the letter is sent notifying a Tier 2 condition had been met.

The clarification that CalCCA therefore sought is that the definition of "days" meant "business days" as is more applicable to business-related activities. In addition, CalCCA sought clarification that the Commission did not intend for infeasible monitoring and that related monitoring calculations could be reasonably performed along with regular accounting processes based on month-end data during normal unaudited financial statement preparation and reviewed to ensure the accuracy of any needed reporting.

IV. CONCLUSION

For the reasons outlined herein, CalCCA recommends the Commission reject the Joint Utilities' protest and adopt the revised Financial Monitoring Guidance Document attached to this Reply.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl
General Counsel and Director of Policy

cc via email:
Service List: R.21-03-011

[11] Joint Utilities' protest at 7.

ATTACHMENT A

TO

CALCCA REPLY TO JOINT UTILITIES' PROTEST TO APPLE VALLEY CHOICE ENERGY ADVICE LETTER 15-E, *ET AL*. (CONSOLIDATED) SUBMITTED BY CALCCA ON BEHALF OF THE JOINT CCAS TO AID IN THE IMPLEMENTATION OF COMMUNITY CHOICE AGGREGATOR FINANCIAL MONITORING AND REPORTING REQUIREMENTS ADOPTED IN DECISION 24-04-009

REVISED FINANCIAL MONITORING GUIDANCE DOCUMENT
REVISED JULY 29, 2024
CLEAN

COMMUNITY CHOICE AGGREGATORS (CCA)
FINANCIAL MONITORING AND REPORTING GUIDELINES
UPDATED JULY 29, 2024

Decision (D.) 24-04-009 adopted two tiers of financial monitoring and reporting requirements for CCAs. Under the first tier, all CCAs, regardless of their financial standing or years of operation, are required to provide the Energy Division with a copy of their most recent audited financial information. The audited financial statement shall be provided once a year, in January or July, whichever comes earlier relative to the availability of the audited financial statement. Under the second tier, CCAs must report additional financial information if they meet certain conditions indicative of financial strain. This guideline document supplements D.24-04-009 with additional guidance on (1) how and when to evaluate the conditions for tier-two financial reporting, and (2) reported financial information for tier-two reporting.

1. Conditions that Trigger Tier-Two Financial Reporting

Tier 2 reporting applies to CCAs that meet any of the following conditions in Table 1:

Table 1: Tier-Two Reporting Conditions

Condition	Explanation
The CCA receives a credit rating below BBB-/Baa3 from S&P & Moody's	This condition applies only to CCAs who are downgraded from an investment grade rating to a noninvestment grade rating. This condition does not require all CCAs to obtain a credit rating.
Days Liquidity on Hand (DLOH) is less than 45 days *Note: this condition triggers Tier 2 reporting only if the Adjusted DSCR trigger is also met.*	DLOH is defined as a CCA's available unrestricted cash and investments and eligible unused bank letters of credit, credit agreements, and capacity under commercial paper programs, multiplied by 365. This amount shall then be divided by the total of the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
Adjusted Debt Service Coverage Ratio (DSCR) is less than 1.0 *Note: this condition triggers Tier 2 reporting only if the DLOH trigger is also met.*	Adjusted DSCR is defined as: Numerator: For the last twelve months, recurring revenue plus interest income plus withdrawals from a Rate Stabilization Fund, minus recurring cash operating expenses and General Fund Transfers over the prior twelve-month period (where recurring revenue and recurring expenses exclude special, one-time items, and annual operating expenses exclude depreciation and amortization expenses).

	Denominator: Aggregate debt service over the prior twelve-month period (i.e., principal, interest, and fees, as applicable, associated with the debt).
Cash reserves for the CCA fall below 5 percent of annual expenses	Cash reserves are defined as cash, cash equivalents, short-term investments, and unused credit facilities. The measure of cash reserves must be directly tied to the CCA. It shall not consider a city's general fund cash reserves. Where "annual expenses" are defined as the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment	This condition is specific to the occurrence of an event of default for buyer non-payment after opportunities for disputes and cures have been exhausted as provided within the contract.
The CCA defaults to its CAISO scheduling coordinator due to non-payment	N/A
The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur	N/A

2. Tier-Two Reporting Requirements

The following conditions must be reported via a letter to the Director of Energy Division within 10 business days of the occurrence:

- The CCA receives a credit rating below BBB-/Baa3 from S&P & Moody's;
- The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment;
- The CCA defaults to its CAISO scheduling coordinator due to non-payment; and
- The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur.

The following conditions must be reported via a letter to the Director of Energy Division within 10 business days of the CCA's acceptance of a financial statement:[1]

- DLOH is less than 45 days and DSCR is less than 1.0; and

[1] CCAs regularly review and update financial statements. Unaudited financial statements should be prepared as soon as practicable and, in any event, within sixty days after the end of each month in which the trigger occurred. If updated financial information is obtained after such submittal, the CCA will provide that update to the Director of the Energy Division to help inform any prior trigger reporting.

- Cash reserves for the CCA fall below 5 percent of annual expenses.

Upon meeting any of the Tier 2 reporting conditions above and submitting the letter to Energy Division, the CCA must meet with Energy Division as requested, up to one meeting per month, and provide the following information:

- Energy and hedging contracts for the next six months with term details;
- Status of all procurement contracts, in particular, those at risk of default;
- Detailed financial information as requested by the Commission including, but not limited to, the CCA's most recent financial statements and DLOH;
- Plan for financial correction and/or market exit.

3. Graduating from Tier-Two Reporting Requirements

A CCA will graduate from the Tier 2 reporting requirements if it does not meet any Tier 2 triggers (except for the insolvency/bankruptcy condition) for six consecutive months.

4. Confidentiality

If a CCA believes that its letter notifying the Energy Division of a triggered Tier 2 condition, or any of its attendant reporting, is market sensitive, the CCA must follow the regular Commission process for securing confidential treatment.

5. Enforcement

A CCA that fails to submit a letter to the Energy Division by the deadlines outlined in Section 2 will incur a penalty of $1,000 per incident plus $500 per day for the first ten days the filing was late and $1,000 for each day thereafter. Commission Staff and the Commission may take any action provided by law to recover unpaid penalties and ensure compliance with applicable statutes and Commission orders, decisions, rules, directions, demands, or requirements.

ATTACHMENT B

TO

CALCCA REPLY TO JOINT UTILITIES' PROTEST TO APPLE VALLEY CHOICE ENERGY ADVICE LETTER 15-E, *ET AL*. (CONSOLIDATED) SUBMITTED BY CALCCA ON BEHALF OF THE JOINT CCAS TO AID IN THE IMPLEMENTATION OF COMMUNITY CHOICE AGGREGATOR FINANCIAL MONITORING AND REPORTING REQUIREMENTSADOPTED IN DECISION 24-04-009

REVISED FINANCIAL MONITORING GUIDANCE DOCUMENT
REVISED JULY 29, 2024
REDLINED

COMMUNITY CHOICE AGGREGATORS (CCA)
FINANCIAL MONITORING AND REPORTING GUIDELINES
UPDATED JULY 29~~1~~, 2024

Decision (D.) 24-04-009 adopted two tiers of financial monitoring and reporting requirements for CCAs. Under the first tier, all CCAs, regardless of their financial standing or years of operation, are required to provide the Energy Division with a copy of their most recent audited financial information. The audited financial statement shall be provided once a year, in January or July, whichever comes earlier relative to the availability of the audited financial statement. Under the second tier, CCAs must report additional financial information if they meet certain conditions indicative of financial strain. This guideline document supplements D.24-04-009 with additional guidance on (1) how and when to evaluate the conditions for tier-two financial reporting, and (2) reported financial information for tier-two reporting.

1. Conditions that Trigger Tier-Two Financial Reporting

Tier 2 reporting applies to CCAs that meet any of the following conditions in Table 1:

Table 1: Tier-Two Reporting Conditions

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Days Liquidity on Hand (DLOH) is less than 45 days *Note: this condition triggers Tier 2 reporting only if the Adjusted DSCR trigger is also met.*	DLOH is defined as a CCA's available unrestricted cash and investments and eligible unused bank letters of credit, credit agreements, and capacity under commercial paper programs, multiplied by 365. This amount shall then be divided by the total of the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
Adjusted Debt Service Coverage Ratio (DSCR) is less than 1.0 *Note: this condition triggers Tier 2 reporting only if the DLOH trigger is also met.*	Adjusted DSCR is defined as: Numerator: For the last twelve months, recurring revenue plus interest income plus withdrawals from a Rate Stabilization Fund, minus recurring cash operating expenses and General Fund Transfers over the prior twelve-month period (where recurring revenue and recurring expenses exclude special, one-time items, and annual operating expenses exclude depreciation and amortization expenses).

	Denominator: Aggregate debt service over the prior twelve-month period (i.e., principal, interest, and fees, as applicable, associated with the debt).
Cash reserves for the CCA fall below 5 percent of annual expenses	Cash reserves are defined as cash, cash equivalents, short-term investments, and unused credit facilities. The measure of cash reserves must be directly tied to the CCA. It ~~should~~shall not consider a city's general fund cash reserves. Where "annual expenses" are defined as the last twelve months of the CCA's operating and maintenance expenses, excluding depreciation and amortization.
The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment	This condition is specific to the occurrence of an event of default for buyer non-payment after opportunities for disputes and cures have been exhausted as provided within the contract.
The CCA defaults to its CAISO scheduling coordinator due to non-payment	N/A
The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur	N/A

2. Tier-Two Reporting Requirements

The following conditions must be reported via a ~~confidential~~ letter to the Director of Energy Division within 10 business days of the occurrence:

- The CCA receives a credit rating below BBB-/Baa3 from S&P & Moody's;
- The CCA defaults on one or more procurement contracts required to meet RA requirements due to non-payment;
- The CCA defaults to its CAISO scheduling coordinator due to non-payment; and
- The CCA becomes insolvent or files for bankruptcy, or the CCA has a reasonable expectation that either event will occur.

The following conditions must be reported via a ~~confidential~~ letter to the Director of Energy Division within 10 business days of the CCA's acceptance of a financial statement:[1]

- DLOH is less than 45 days and DSCR is less than 1.0; and

[1] CCAs regularly review and update financial statements. Unaudited financial statements should be prepared as soon as practicable and, in any event, within sixty days after the end of each month in which the trigger occurred. If updated financial information is obtained after such submittal, the CCA will provide that update to the Director of the Energy Division to help inform any prior trigger reporting.

- Cash reserves for the CCA fall below 5 percent of annual expenses.

Upon meeting any of the Tier 2 reporting conditions above and submitting the ~~confidential~~ letter to Energy Division, the CCA must meet with Energy Division as requested, up to one meeting per month, and provide the following information:

- Energy and hedging contracts for the next six months with term details;
- Status of all procurement contracts, in particular, those at risk of default;
- Detailed financial information as requested by the Commission including, but not limited to, the CCA's most recent financial statements and DLOH;
- Plan for financial correction and/or market exit.

3. Graduating from Tier-Two Reporting Requirements

A CCA will graduate from the Tier 2 reporting requirements if it does not meet any Tier 2 triggers (except for the insolvency/bankruptcy condition) for six consecutive months.

4. Confidentiality

If a CCA believes that its letter notifying the Energy Division of a triggered Tier 2 condition, or any of its attendant reporting, is market sensitive, the CCA ~~should~~must follow the regular Commission process for securing confidential treatment.

5. Enforcement

A CCA that fails to submit a letter to the Energy Division by the deadlines outlined in Section 2 will incur a penalty of $1,000 per incident plus $500 per day for the first ten days the filing was late and $1,000 for each day thereafter. Commission Staff and the Commission may take any action provided by law to recover unpaid penalties and ensure compliance with applicable statutes and Commission orders, decisions, rules, directions, demands, or requirements.

AUGUST FILINGS

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

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SUMMARY OF COMMENTS

- The proposed *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources* (Proposed Decision) errs by omitting necessary details regarding the relationship between the central procurement entity's (CPE) procurement and the load-serving entities' (LSE) planning and procurement activities:
    - The Proposed Decision must recognize the inherent interactions between central procurement and the Reliable and Clean Power Procurement Program that cannot be untangled;
    - The Proposed Decision errs by neglecting to include LSE self-procurement as a step in the process; and
    - The Proposed Decision errs by not making all efforts to support customer affordability through the ability to transact attributes of CPE-allocated resources.
- The Proposed Decision errs by basing its procurement cap on analysis that does not demonstrate a clear need for the technologies and amounts ordered:
    - The Proposed Decision errs in its definition of eligible resources;
    - The Proposed Decision bases its procurement caps on unsupported analysis; and
    - If the California Public Utilities Commission foregoes CalCCA's recommendation to revisit the need for central procurement in future Integrated Resource Planning cycles, it must modify the Proposed Decision to lower the procurement cap.
- The Proposed Decision fails to recommend the CPE retain an expert consultant to maximize state and federal funding opportunities.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*[3] (Proposed Decision or PD), dated July 19, 2024.

I. INTRODUCTION

CalCCA appreciates the Administrative Law Judge's (ALJ) and Commission staff's significant efforts to make an initial need determination and develop the process for central procurement under the provisions of Assembly Bill 1373 (Stats. 2023, Ch.367) (AB 1373). However, the PD misses the mark on several points with respect to these processes' interactions with load-serving entities' (LSEs) own planning and procurement activities as part of their right to self-procure for identified needs. The PD's statement that "…it is logical to keep any CPE procurement as a result of this order separate and apart from any individual LSE requirements driven by the [Reliable and Clean Power Procurement Program (RCPPP)], once adopted,"[4] and finding that "CPE procurement should be kept in a separate category for purposes of consideration of an RCPPP in the

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[3] Proposed *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, Rulemaking (R.) 20-05-003 (July 19, 2024).

[4] *Id.* at 50.

future in this proceeding,"[5] are false. Central procurement will interact with or, at minimum, significantly impact LSEs' own procurement and planning processes. Therefore, it is necessary to modify the PD to more completely document central procurement entity (CPE) processes, its interactions with LSE procurement, and LSEs' abilities to optimize their procurement plans through self-procurement and transacting CPE allocations.

The PD also fails to make its need determination based on a well-supported analysis of the need for the technologies and amounts ordered in the PD. While CalCCA supports the PD's finding that there is not a need for central procurement of out-of-state wind, the other technologies in the PD and their amounts are not justified. Ordering central procurement that does not have a demonstrated potential for net benefits is a risky and potentially unaffordable endeavor that could hinder LSE procurement and increase customer costs. Because its analysis does not demonstrate a clear need, the Commission should not direct Department of Water Resources (DWR) to centrally procure in this cycle and should instead revisit central procurement in future Integrated Resource Plan (IRP) cycles. If the Commission forgoes this recommendation and makes a need determination for the initial September 1, 2024, statutory requirement, the Commission should modify its procurement cap to better target the infrastructure development necessary to "help bring emerging technologies to scale"[6] and better reflect the most up-to-date LSE procurement and planning information.

The PD also fails to develop a central procurement process and recommendations to the CPE that make "all possible efforts… to contain costs, reduce ratepayer risk, and seek other sources of funding to reduce development costs and share in the long-term costs and benefits."[7] The Commission must revise the PD to address these errors, which include in summary:

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[5] Proposed Decision, Conclusion of Law (COL) 22.
[6] *Id.* at 3.
[7] *Id.*

- The PD errs by omitting necessary details regarding the relationship between the CPE's procurement and the LSE's planning and procurement activities:
    - The PD must recognize the inherent interactions between central procurement and the RCPPP that cannot be untangled;
    - The PD errs by neglecting to include LSE self-procurement as a step in the process; and
    - The PD errs by not making all efforts to support customer affordability through the ability to transact attributes of CPE-allocated resources.
- The PD errs by basing its procurement cap on analysis that does not demonstrate a clear need for the technologies and amounts ordered:
    - The PD errs in its definition of eligible resources;
    - The PD bases its procurement caps on unsupported analysis; and
    - If the Commission foregoes CalCCA's recommendation to revisit the need for central procurement in future IRP cycles, it must modify the PD to lower the procurement cap.
- The PD fails to recommend the CPE retain an expert consultant to maximize state and federal funding opportunities.

Resolving these errors will ensure a well-functioning CPE process that mindfully considers its interactions with LSE procurement and determines needs based on well-supported analysis.

II. THE PROPOSED DECISION ERRS BY OMITTING NECESSARY DETAILS REGARDING THE RELATIONSHIP BETWEEN THE CPE'S PROCUREMENT AND THE LSE'S PLANNING AND PROCUREMENT ACTIVITIES

During the development of AB 1373, the Legislature recognized that:

> Authorizing DWR to procure energy can have the unintended effect of reducing supply in the energy market and increasing prices overall (particularly in the currently constrained energy market). These costs come home to roost on electric utility customer bills. Additionally, market participants, including LSEs, electric POUs, and generators, may elect to delay procurement transactions so as to position themselves for procurement by DWR. In this regard, the state should tread carefully.[8]

Despite this caution, the PD creates uncertainty around how central procurement interacts with LSE procurement, which could exacerbate the negative consequences of central procurement

[8] AB 1373.

conveyed by the Legislature. To reduce this uncertainty, the Commission should revise the PD as outlined in Sections II.A-C to clarify central procurement's interactions with LSE procurement. This is a necessary first step that must be taken prior to developing further operational and implementation details of cost and benefit allocation, as the PD commits to do before or during consideration of DWR contracts.[9]

A. The Proposed Decision Must Recognize the Inherent Interactions Between Central Procurement and RCPPP that Cannot be Untangled

The PD finds that "CPE procurement should be kept in a separate category for purposes of consideration of an RCPPP in the future in this proceeding."[10] This finding introduces many questions that the PD leaves unanswered because central procurement and RCPPP procurement both intend to address GHG-driven procurement needs.[11] In addition, both must factor into reliability planning to prevent costly over-procurement that could exacerbate the current affordability crisis facing the state's customers. Central procurement will inevitably interact with LSE procurement. The PD insufficiently addresses this interaction.

If CPE procurement is kept in a "separate category" from RCPPP procurement, it will be hard to determine how this procurement fits into the state's overall procurement needs. If CPE procurement directives are part of the overall system reliability and GHG-reduction needs, then if the CPE fails to procure or elects not to procure based on the results of its solicitations, then the system will be short from a reliability and GHG-reduction perspective because the CPE's failure to procure would not be accounted for in future need determinations in the RCPPP. Relatedly, if the CPE fails to procure or elects not to procure, it is unclear what steps will be taken to resolve the resulting shortfall, putting the RCPPP's critically important objective of replacing order-by-order

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[9] Proposed Decision, COL 28.
[10] *Id.*, COL 22.
[11] *Id.* at 2 and 50.

procurement requirements in jeopardy. If CPE procurement directives provide capacity in excess of the grid's reliability need, then CPE procurement would contribute to the ongoing affordability crisis by procuring excess capacity from technologies that are not yet cost-effective.

Central procurement will inevitably interact with and significantly impact LSEs' own procurement and planning processes. The Commission must modify the PD to document how the CPE process interacts with LSE procurement, particularly the RCPPP. In particular, the Commission should provide some indication of how and when it will provide certainty to LSEs to avoid unintentionally delaying LSE procurement.

To minimize impacts on LSEs' planning and procurement processes, LSEs should receive frequent status updates on DWR's central procurement activities, including information on the timing of solicitations and notices of project delays. The Commission should also elaborate on how it intends to minimize the use of the CPE once future LSE procurement is known and state affirmatively that attributes allocated to LSEs from CPE procurement can be used for compliance obligations such as RA and RPS. Simply stating that "it is logical to keep any CPE procurement as a result of this order separate and apart from any individual LSE requirements driven by the RCPPP,"[12] is insufficient and leaves all parties unclear of how CPE procurement will impact LSEs' own planning and procurement activities.

B. The Proposed Decision Errs by Neglecting to Include LSE Self-Procurement as a Step in the Process

AB 1373 provides a six-month window between the Commission determining there is a need for central procurement and the Commission requesting DWR to procure. The Legislature made clear that:

> The intent for the six month window is to allow other LSEs the opportunity to procure their share of their load if they elect to do so.

[12] Proposed Decision at 50.

> This approach is a long-held principle of CCAs whose primary (if not exclusive) mission is to procure energy on behalf of their load. Such an approach seems appropriate to ensure LSEs exercise their responsibility to procure resources for their load, prior to a state agency stepping in. In this regard, it's possible DWR procurement may not ever be used, or perhaps only used when truly necessary because the resource was too difficult for any individual LSE, or a few LSEs, to procure.[13]

Despite this clear direction, the PD says nothing about LSEs' ability to procure their share of needed resources to reduce their allocations from DWR procurement. The Commission must modify the PD to create a process in which LSEs show contracts for any long lead-time (LLT) technologies specified in central procurement orders issued by the Commission to DWR. This should include any request made pursuant to this PD and in subsequent IRP cycles. If LSEs show these technologies, each LSE's cost and benefit allocation should be reduced by their shown amount.

While the PD states that it targeted resources "intentionally different from resources already being procured by LSEs directly at sufficient volumes to result in market transformation,"[14] the PD also acknowledges the LLT resources targeted in the PD may have higher costs than prevalent commercialized resources.[15] In this PD, the Commission explicitly identifies a need for pre-commercial technologies with likely higher costs than conventional technologies. Because of these higher costs, it is logical that LSEs would not yet have procured these technologies without a clear indication from the Commission that there is a need for them, which had yet to occur in advance of the PD.

The opportunity to self-procure should be a feature of this initial central procurement order and future central procurement orders, which can be more easily incorporated into LSEs' planning and procurement activities if coordinated with the RCPPP process. Failure to allow self-procurement

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[13] AB 1373 at 14.
[14] Proposed Decision at 49.
[15] *Id.* at 3.

shifts costs onto the customers of early-moving LSEs, deterring early-moving LSEs from procuring quickly to accelerate reliability and decarbonization efforts.

As outlined in Section 4.5 of the PD, it will take time for DWR to begin its solicitations and contracting processes. Self-procurement can occur at least until the Commission issues its procurement request and DWR is ready to start its solicitations. For these reasons, the PD errs by neglecting to include an LSE self-procurement step in the CPE process. The Commission should revise the PD to allow LSEs to demonstrate procurement to lower their CPE allocations during the six-month window between the September 1, 2024, need determination and the procurement request to DWR.

C. The Proposed Decision Errs by Not Making all Efforts to Support Customer Affordability through the Ability to Transact Attributes of CPE-Allocated Resources

The PD states:

> … this decision recognizes that electricity rates are rising, creating hardships for ratepayers. Though the DWR centralized procurement mechanism should help bring emerging technologies to scale, the cost of these investments will ultimately impact electricity bills. Accordingly, all possible efforts should be made to contain costs, reduce ratepayer risk, and seek other sources of funding to reduce development costs and share in the long-term costs and benefits.[16]

To accomplish this critically important objective, the Commission must modify the PD to incorporate a key component of affordability: the ability for LSEs to transact attributes allocated from the CPE. Allowing LSEs to transact attributes enables LSEs to manage their resources and attributes in the most cost-effective manner, increasing market liquidity and putting downward pressure on prices for scarce supply. Allowing LSEs with excess attributes to offer to sell their surplus to other LSEs willing to buy will ensure the Commission achieves its objective of making all efforts to promote customer affordability, without jeopardizing reliability and state policy goals.

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[16] Proposed Decision at 3.

The PD states, that "[f]urther operational and implementation details of the allocation of costs and benefits of CPE procurement to LSEs will be handled in this proceeding or its successor before or during consideration of actual contracts to be signed by DWR."[17] The Commission should modify the PD to explicitly include CPE allocation transactions within the scope of issues that will be resolved before DWR contracting opportunities.

III. THE PROPOSED DECISION ERRS BY BASING ITS PROCUREMENT CAP ON ANALYSIS THAT DOES NOT DEMONSTRATE A CLEAR NEED FOR THE TECHNOLOGIES AND AMOUNTS ORDERED

The PD finds an initial need determination of 10.6 gigawatts (GW) of nameplate capacity of the following technologies: up to 7.6 GW of offshore wind (OSW), up to 1 GW of enhanced geothermal systems (EGS), up to 1 GW of multi-day long-duration energy storage (LDES), and up to 1 GW of LDES with a discharge period of at least 12 hours.[18] The PD defines the technologies eligible for central procurement in a way that will not mitigate risk and ensure cost containment. It also bases its procurement caps on unsupported conclusions that may result in crowding out a significant amount of LSE procurement for the foreseeable future. Procurement caps that are too high result in higher levels of uncertainty. This uncertainty will result in more risks for LSEs trying to manage their portfolios with uncertain amounts of attributes and associated costs allocated to them. It also increases the potential for developers to reduce their participation in LSE solicitations in favor of uncertain central procurement opportunities.

For these reasons, the Commission should not find a need for central procurement for the September 1, 2024, deadline, and instead, work on (1) building a record that better informs the need for central procurement, and (2) refining the central procurement process within the context of the forthcoming RCPPP. If the Commission foregoes this recommendation and makes a need

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[17] Proposed Decision, COL 28.

[18] *Id.* at 2.

determination for central procurement on September 1, 2024, the Commission should only direct the procurement of the minimum amount of OSW in federal leased areas needed to establish the requisite infrastructure to kickstart the development (1 GW).[19] The Commission should not direct central procurement of EGS or LDES.

A. The Proposed Decision Errs in Its Definition of Eligible Resources

The PD states it focuses central procurement on technologies the Commission believes "could be important to the electricity sector as a whole in achieving California's Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018) goals by 2045, but which will be inherently more expensive due to their emerging nature and the fact that they are not currently commercially available at competitive prices."[20] This definition allows for the possibility of ordering central procurement of resources with excessive risks and a low benefit-to-cost ratio, resources that do not meet the statutory definition of LLT for the purposes of central procurement, or resources that LSEs have already demonstrated the ability to procure.

EGS and LDES are not good candidates for central procurement. First, LDES resources do not consistently meet the statutory definition of LLT (requiring 5 years for construction and development), depending on the project. Additionally, there is no evidence that LSEs cannot and would not procure these resources if they are available and cost-effective. LSEs have already demonstrated the ability to procure EGS, in addition to conventional geothermal projects, and LDES projects, both individually and jointly. The Commission has yet to conduct a cost-benefit analysis on these technologies, however, so it is unknown whether central procurement of these technologies has

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[19] *Administrative Law Judge's Ruling Seeking Comments on Need and Process for Centralized Procurement of Specified Long Lead-Time Resources*, R.20-05-003 (Apr. 26, 2024) at 17-20: This Ruling established 1 GW as the "estimated minimum viable project size" and finds 1 GW as the most likely amount to maximize ratepayer benefits under most scenarios.

[20] Proposed Decision at 37.

greater net benefits than an alternative combination of resources with an equivalent profile procured by LSEs. Finally, the Commission defines the need specifically for EGS and non-lithium-ion or pumped storage hydro LDES and splits the LDES requirement into multi-day and 12+ hour LDES. This definition carves out an overly specific need that may only be filled by a few developers when the actual need could have been filled by a broader set of technologies, including those LSEs have proven the ability to procure already. The result is the potential for non-competitive results to DWR's solicitation for a need that is too targeted. For these reasons, the Commission should not direct central procurement of EGS or LDES,

OSW may be the only reasonable candidate for central procurement. LSEs have demonstrated that size is not a barrier to procurement (e.g., OOS-wind procurement). Rather, it is the significant infrastructure investment required for OSW development (e.g., port infrastructure, transmission development, etc.) that presents hurdles that must be overcome regardless of the procuring entity. Additionally, while the cost-effectiveness of OSW is still questionable, it is possible that an alternative combination of resources with an equivalent profile could serve the same need at a potentially lower cost. Still, emerging technologies are typically high-risk, and central procurement may make sense when investments will result in spurring future development opportunities for LSEs, enhancing development efficiencies, or promoting economies of scale.

To tighten the definition of eligible resources in advance of ordering central procurement, the Commission should build a record (1) demonstrating that the technologies identified can help the state meet SB 100 goals at costs*, inclusive of the market transformation costs,* that are lower than those for meeting SB 100 goals with an alternative portfolio of current technologies procured by

LSEs and (2) defining "5 years for construction and development,"[21] and demonstrate in the record that these technologies necessarily take longer than five years to construct and develop. The analysis in the record thus far does not adequately demonstrate the estimated costs of central procurement are lower than an alternative portfolio procurement by LSEs. Nor does it conclude that LDES technologies have construction and development times of more than five years or demonstrate net benefits for these technologies. 12+-hour LDES and multi-day LDES have yet to be properly modeled in the preferred system plan (PSP) due to a lack of sufficient cost information. Building a record to support these findings before ordering central procurement will ensure the Commission appropriately manages the risks of central procurement of emerging technologies and adheres to the statutory definition of LLT resources.

B. The Proposed Decision Bases Its Procurement Caps on Unsupported Conclusions

In justifying the procurement caps ordered in the PD, the Commission concludes:

> It is reasonable to ask DWR to solicit approximately half of the resource need identified in the most recent adopted PSP portfolio in D.24-02-047 for LDES and geothermal, in order to facilitate a downpayment on technologies necessary to achieve SB 100 goals, while still leaving room for LSEs to procure the technologies individually, after costs are reduced and market transformation is underway.[22]

It also concludes:

> It is reasonable to ask DWR to solicit for 7.6 GW nameplate of OSW, which signals a strong interest in developing the resource, represents the level beyond which our staff cost-benefit analysis shows the potential for higher risks to ratepayers, is sufficient to foster cost savings as the resource is developed at scale, and avoids the potential for market power issues.[23]

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[21] The definition of a resource's construction and development must not include interconnection and transmission development to ensure the focus of central procurement is truly on resources themselves that are LLT.

[22] Proposed Decision, COL 17.

[23] Proposed Decision, COL 18.

The PD does not support these conclusions with evidence in the record indicating that the deployment of the scale identified in the PD will result in market transformation sufficient to bring costs down below the costs of meeting SB 100 targets with conventional technologies. Instead, the PD bases its procurement amounts on a PSP with outdated cost assumptions for OSW, a cost-benefit analysis that shows negative net benefits in most scenarios at the volume of OSW ordered, and no cost-benefit analysis for LDES or EGS.

Setting a procurement cap that may or may not be cost-effective without working on infrastructure issues will not result in sufficient room for LSEs to procure on their own and may result in market power issues. Simply shifting the procurement responsibility from LSEs to a CPE does not resolve issues with transmission, port infrastructure, and interconnection. Therefore, the market will likely experience increased costs and limited project availability as a result of the Commission's recommendation that these technologies be considered by DWR for central procurement. With project interconnection timelines now exceeding seven years from interconnection request to commercial operation in many cases,[24] the Commission's central procurement directive may result in merely cutting off direct LSE procurement of these technologies for years into the future.

Ordering roughly 50 percent of OSW capacity in the PSP is likely too high compared to what is needed to transform the OSW industry and would very likely stifle developers' willingness to offer projects to LSEs. As it stands, the need determination in the PD is an after-the-fact analysis of plans completed by LSEs that did not have advanced notice that these three categories of technologies

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[24] The time it takes between interconnection request and interconnection agreement can take over two years: https://www.caiso.com/documents/mergedpresentations-resourceinterconnectionfair-march032021.pdf. The time from interconnection agreement to commercial operations takes over six years on average: Lawrence Berkely National Lab, Queued Up: 2024 Edition, Slide 39: https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

were needed or required. The PD states, "[t]he November 1, 2022 individual LSE IRP filings, along with their August 1, 2023 and December 1, 2023 procurement data filings, do not show LLT resources under contract to LSEs in sufficient quantities to achieve scale and cost reductions in the long run." It provides no compelling evidence, however, identifying the "sufficient quantity" of LLT resources necessary "to achieve scale and cost reduction in the long run." The Department of Energy's recent Pathways to Commercial Liftoff report for Offshore Wind report[25] suggests the Commission's need determination of 7.6 GW of OSW significantly exceeds the amount of early commercial deployments necessary to scale-up emerging technologies.[26]

Therefore, if the Commission foregoes the recommendation to reconsider central procurement needs in a future IRP cycle, the Commission must also consider the most up-to-date information provided by the LSEs on their procurement activity, including the June 1, 2024, IRP filings. The Commission should account for planned procurement that would result in LSEs contracting at a later time and still bringing those resources to commercial operation in time to meet their needs. As described in section II.B, it must also provide LSEs the opportunity to lower their share of central procurement amounts during the six months between need determination and procurement request. Only after a need determination and procurement request would LSEs have a clear indication of the need.

C. If the Commission Foregoes CalCCA's Recommendation to Revisit the Need for Central Procurement in Future IRP Cycles, it Must Modify the Proposed Decision to Lower Procurement Cap

Sections III.A and III.B above demonstrate the need to continue building the record before ordering DWR to conduct central procurement of LLT resources. If the Commission foregoes

[25] United States Department of Energy. *Pathways to Commercial Liftoff: Offshore Wind* (Apr. 2024).

[26] The Department of Energy identifies a need for 10-15 GW nationwide of early commercial deployments to ultimately unlock over 100 GW of scale-up, representing roughly 10% of the target.

additional record development before ordering DWR procurement, the Commission must direct the procurement of only the minimum amount of OSW in federal leased areas needed to establish the requisite infrastructure to kickstart the development (1 GW). The central procurement of OSW could benefit from coordinating procurement and infrastructure development, but only in modest amounts, given the results of the Commission's cost-benefit analysis[27] and the negative interactions central procurement can have with LSE procurement.

One GW of OSW central procurement is most consistent with the cost-benefit analysis in the ALJ Ruling, which suggests the highest potential net benefits at lower levels of OSW procurement. Higher amounts of OSW central procurement or central procurement of technologies beyond OSW would overly concentrate SB 100's success on the CPE endeavor, ignoring the successes of LSEs procuring to meet a clearly identified and communicated need, adding competition for scarce resources and interconnection capacity, and undermining affordability.

The higher the potential central procurement cap, the harder it is for LSEs to plan around and the greater the degree of risk associated with CPE failure. Certainty and transparency around DWR's central procurement is imperative to minimize negative impacts and interactions with LSE procurement processes. The larger the potential size of the CPE procurement, the greater the risk for LSEs and the harder it is for LSEs to manage their own portfolios given the uncertainty in DWR's final contracted volumes and the LSE's allocation. Given the importance of providing certainty for LSE procurement planning and risk mitigation, the central procurement cap in this initial need determination should be a modest hard cap. This amount can be revised upward in future IRP cycles

[27] The Commission's OSW cost-benefit analysis finds, even 1-3 GW of OSW procurement may come at a net cost, though total ratepayer impact would be small. It finds "[l]ower amounts of offshore wind generally minimize[es] total ratepayer cost and risk" and "[i]nitial OSW procurement [of 1-3 GW] can support market transformation with limited ratepayer risk." *Analysis for Centralized Procurement of Specified Long Lead-Time Resources* (April 2024), at 41.

after considering the most up-to-date LSE planning and procurement information once LSEs have had an opportunity to develop their plans in light of this newly identified need. The Commission must render formal decisions for any subsequent need determinations in future IRP cycles to ensure parties have sufficient ability to vet the need determination, supporting analysis, and resulting allocations.

IV. THE PROPOSED DECISION FAILS TO RECOMMEND THE CPE RETAIN AN EXPERT CONSULTANT TO MAXIMIZE STATE AND FEDERAL FUNDING OPPORTUNITIES

CalCCA strongly supports the Commission's goal to make "all possible efforts… to contain costs, reduce ratepayer risk, and seek other sources of funding to reduce development costs and share in the long-term costs and benefits."[28] To ensure the PD results in a process that takes advantage of all possible sources of funding to reduce costs, the Commission should revise the PD to recommend that DWR have dedicated staff members or consultants who investigate grant opportunities and assist potential project developers in reducing costs by maximizing the use of funding opportunities in its centralized procurement efforts.

V. CONCLUSION

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

Respectfully submitted,

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

August 8, 2024

[28] Proposed Decision at 3.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

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

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **bold and underlined**

FINDINGS OF FACT

2. The resource type~~**s**~~ considered for a need determination for centralized procurement ~~**are geothermal, LDES, OOS wind, and**~~ **is** OSW.

4. EGS is an emerging technology distinct from conventional geothermal, and is the subject of an initiative at DOE called "Enhanced Geothermal Shot" designed to reduce the costs of EGS. **However, the costs and benefits are not known at this time and the length of time for construction and development has not been demonstrated to exceed five years.**

5. 12+-hour LDES and multi-day LDES are emerging technologies that are not yet sufficiently available with known costs to be modeled in previous PSP portfolios adopted by the Commission. Therefore, proxies have been used. **As such, the cost-effectiveness of these resources is not known.**

8. As of this decision, almost no LSEs have EGS, 12+-hour LDES, multi-day LDES, or OSW projects under contract. Those LSEs that do have these types of projects do not have any significant volumes under contract relative to the size of the resource potential or in enough quantities to spur market transformation. **Given the recent development in EGS, LDES, and OSW, additional time is needed for LSEs to pursue contracting of these resources before determining a central procurement need.**

12. The November 1, 2022**,** individual LSE IRP filings **did not** represent~~ed~~ the CCAs' opportunity to offer proposals under Section 454.51(d) requirements**, because the Commission had not yet identified a need for centrally procured technologies.**

13. The November 1, 2022**,** individual LSE IRP filings, along with their August 1, 2023**,** and December 1, 2023**,** procurement data filings, do not show LLT resources under contract to LSEs in sufficient quantities to achieve scale and cost reductions in the long run. **Any new efforts in procurement plans by the LSEs should be used to update the need analysis prior to finalizing any central procurement.**

CONCLUSIONS OF LAW

7. The Commission should reevaluate the need for centralized procurement of LLT resources in each IRP cycle, **in concert with evaluating the need for LSE procurement in the RCPPP,** when considering the adoption of a PSP portfolio.

10. Resources that are important to reducing the overall emissions in the electricity sector, but which may not compete favorably in price against other resources, should be considered for centralized procurement **after LSEs have an opportunity to demonstrate contracts for the newly identified need**.

14. The Commission should not~~**, at this time,**~~ ask DWR to solicit for resource types that are already being widely procured in significant volumes by numerous individual LSEs.

~~**16. LDES requested for DWR to solicit for centralized procurement should include 12+-hour LDES and multi-day LDES, but not lithium-ion batteries or PSH.**~~

~~**17. It is reasonable to ask DWR to solicit approximately half of the resource need identified in the most recent adopted PSP portfolio in D.24-02-047 for LDES and geothermal, in order to facilitate a downpayment on technologies necessary to achieve SB 100 goals, while still**~~

~~**leaving room for LSEs to procure the technologies individually, after costs are reduced and market transformation is underway.**~~

18. It is reasonable to ask DWR to solicit for ~~**7.6**~~ **1** GW nameplate of OSW **at most**, which signals a strong interest in developing the resource **and establishing the requisite infrastructure to kickstart this development**, ~~**represents the level beyond which our staff cost-benefit analysis shows the potential for higher risks to ratepayers,**~~ is sufficient to foster cost savings as the resource is developed at scale **by LSEs**, and avoids the potential for market power issues.

19. Centralized procurement of LLT resources should be considered by the Commission in ~~**a separate category from**~~ **concert with** individual LSE procurement **resulting from the RCPPP**.

20. Any CPE procurement should not count toward the requirements of D.21-06-035, D.23-02-040, or D.24-02-047**, but may count for future RCPPP procurement requirements.**

~~**21. The Commission should evaluate in subsequent AB 1373 need determinations the LSE progress toward the D.21-06-035 requirements for procurement of 1 GW of high-capacity-factor clean LLT resources and consider whether additional CPE procurement of conventional geothermal resources is necessary.**~~

~~**22. CPE procurement should be kept in a separate category for purposes of consideration of an RCPPP in the future in this proceeding.**~~

23. AB 1373 ~~**does not**~~ provides an opportunity for LSEs ~~**to opt out of centralized**~~ conduct their share of procurement during the six months between when the Commission makes its need determination and ~~**once the Commission has made**~~ **its procurement request**~~**need determination**~~**.** ~~**LSEs subject to the Commission's IRP purview should not be allowed to opt out of paying for their share of centralized procurement.**~~

28. Further operational and implementation details of the allocation of costs and benefits of CPE procurement to LSEs**, including the ability for LSEs to transact allocations,** will be handled in this proceeding or its successor before or during consideration of actual contracts to be signed by DWR.

~~**40. The Commission should not need to render a second formal decision during the six-month window after September 1, 2024, and after any subsequent need determination in future IRP cycles. The request for procurement after the Commission's formal need determination in a decision may come in the form of a letter to DWR from the Commission president and/or the assigned Commissioner to the IRP rulemaking, consistent with the provisions of this decision.**~~

New: The Commission should recommend that DWR retain an expert consultant or staff to advise on all alternative sources of funding, like federal and state funds, to contain costs of central procurement.

New: Net benefits that demonstrate the technologies identified can help the state meet SB 100 goals at costs, inclusive of the market transformation costs, that are lower than those for meeting SB 100 goals with an alternative portfolio of conventional technologies should be an explicit and important criterion for the selection of resources to be centrally procured.

ORDERING PARAGRAPHS

1. The Commission has evaluated eligible resource types under Public Utilities Code Section 454.52(h)(1)-(2) categories and has determined that there is a need for centralized procurement through competitive solicitations by the Department of Water Resources (DWR) as a Central Procurement Entity for the following resource**s**, in nameplate capacity, with energy deliveries and/or capacity online between June 1, 2031 and June 1, 2037. DWR is not required to procure all of the below resources and may procure as little as zero, depending on the reasonableness of prices offered by developers:

~~**(a) A maximum of 1,000 megawatts (MW) of Enhanced Geothermal Systems, as defined by the United States Department of Energy's "Enhanced Geothermal Shot" initiative;**~~

~~**(b) A maximum of 1,000 MW of long-duration energy storage (LDES) that can discharge for 12 hours or more that does not employ lithium-ion batteries or pumped storage hydroelectric (PSH) technologies;**~~

~~**(c) A maximum of 1,000 MW of multi-day LDES that does not employ lithium-ion batteries or PSH technologies; and**~~

(**a**~~**d**~~) A maximum of ~~**7,600**~~ **1,000** MW of offshore wind.

3. **After the completion of the self-procurement period,** ~~**A**~~**a**ll load-serving entities with obligations under the integrated resource planning process of the Commission related to Public Utilities Code Sections 454.51 and 454.52 shall be required to pay for their proportional share**, adjusted for self-procurement,** of any resources determined to be needed by the Commission and centrally procured by the Department of Water Resources for the life of the contracts, once approved by the Commission.

4. The costs and benefits of any procurement of offshore wind ~~**and enhanced geothermal systems**~~ shall be allocated annually on the basis of forecast energy load share, for the life of each contract.

~~**5. The costs and benefits of any procurement of long-duration energy storage shall be allocated annually to each transmission access charge area based on forecast 12-month peak load, and then further allocated to each load-serving entity's customers in the same manner as the Cost Allocation Mechanism adopted in Decision 06-07-029, for the life of each contract.**~~

New: The Commission recommends that the Department of Water Resources retain an expert consultant or staff member to advise on all alternative sources of funding, such as state and federal funding to contain the costs of central procurement.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

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August 13, 2024

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should reject parties' recommendations to revise the Proposed Decision to order higher amounts of central procurement;

- California Wind Energy Association's recommendation that the Commission explicitly ask Department of Water Resources to consider procurement of the CADEMO project illustrates the negative consequences of central procurement and must be rejected;

- The Commission must reject parties' recommendations that prevent load-serving entity participation in the procurement review group; and

- Parties' comments affirm that a future track of this proceeding to discuss cost allocation is warranted.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION DETERMINING NEED FOR CENTRALIZED PROCUREMENT OF LONG LEAD-TIME RESOURCES

The California Community Choice Association (CalCCA) submits these Reply Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[1] on the proposed *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*[2] (Proposed Decision or PD), dated July 19, 2024.

I. THE COMMISSION SHOULD REJECT PARTIES' RECOMMENDATIONS TO REVISE THE PD TO ORDER HIGHER AMOUNTS OF CENTRAL PROCUREMENT

Some parties provided opening comments[3] recommending the Commission increase its initial need determination.[4] While these parties provide no support justifying their recommendations, other parties rightly note that the Commission did not find a clear need for the amounts and technologies ordered in the PD,[5] load-serving entities (LSEs) have already demonstrated the ability to procure long-lead-time (LLT) resources,[6] and the amounts ordered in the PD create risks of over- or under-procurement.[7] For the reasons described below, the PD's need determination is already too high. The Commission should dismiss parties' recommendations to increase its initial need determination and instead recommend DWR consider central procurement of, at most, 1 gigawatts (GW) of offshore wind (OSW) only after considering updated LSE procurement statuses.

First, the Commission has not clearly demonstrated a need for enhanced geothermal systems (EGS) or long-duration energy storage (LDES) central procurement. Unlike for OSW, the Commission has not conducted a cost-benefit analysis for these technologies, and as noted by several parties,[8] the

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[1] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[2] Proposed *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, Rulemaking (R.) 20-05-003 (July 19, 2024).

[3] All references herein to party comments are to the Opening Comments filed in this proceeding, R.20-05-003, on August 8, 2023.

[4] Offshore Wind California Opening Comments at 2, RWE Offshore Wind Holdings LLC at 2, Environmental Defense Fund (EDF) Opening Comments at 9-10.

[5] Pacific Gas and Electric Company (PG&E) Opening Comments at 2-3 and 5-6, and Southern California Edison Company (SCE) Opening Comments at 3-6.

[6] SCE Opening Comments at 6-8, and the Public Advocates Office of the California Public Utilities Commission (Cal Advocates) Opening Comments at 2-3.

[7] SCE Opening Comments at 9-11.

[8] Cal Advocates Opening Comments at 5, PG&E Opening Comments at 6, and SCE Opening Comments at 3-6.

Commission has not found a need for EGS or LDES in the preferred system plan. In addition, these technologies have already been offered in LSEs' own solicitations,[9] and LSEs have already contracted for EGS, demonstrating that LSEs can procure these LLT resources without the California Department of Water Resources (DWR) procuring them first.[10] Requesting DWR procure these resources in competition with LSEs will make it even more challenging for LSEs to meet existing and future compliance requirements.

Second, as noted by PG&E and SDG&E, the amount of OSW included in the PD's need determination is not aligned with the results of the cost-effectiveness analysis.[11] Increasing the need determination for OSW would exacerbate the PD's error by increasing the risk central procurement will not be cost-effective. RWE OSW Holdings LLC's suggests that an increased need determination for central procurement is needed to ensure "market transformation."[12] Market transformation will result from infrastructure development, which is necessary to support any amount of procurement, whether procured via LSEs or DWR. The larger the central procurement need determination, the higher the risk of over or under-procurement. As SCE notes:

> Because no LSE can know what specific amount...the CPE will procure (much less come on-line), it is impossible to determine whether all, some, or none of the 7,600 MW procurement target will be relied upon to meet the state's GHG and/or reliability requirements. LSEs would have no ability to determine or plan for the position when they make procurement decisions. Depending on an LSE's assumptions, this could result in over- or under-procurement through no fault of the LSEs, especially since the proposed OSW target is so large and the actual amount of OSW to be procured by DWR is uncertain.[13]

The Commission should keep procurement amounts small to mitigate risk and costs while still driving infrastructure development.

EDF recommends higher procurement stating, "DWR, unlike individual LSEs, can temper ratepayer impacts by using low-cost government bonds, waiting to begin recovering the cost of resources from individual LSEs and customers until the projects provide energy benefits, and

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[9] SCE Opening Comments at 7-8 and San Diego Gas and Electric Company (SDG&E) Opening Comments at 4.

[10] SCE Opening Comments at 6-8.

[11] PG&E Opening Comments at 2 and SDG&E Opening Comments at 6.

[12] RWE Offshore Wind Holdings LLC Opening Comments at 2.

[13] SCE Opening Comments at 10.

spreading out the cost of this development across decades."[14] DWR financing the cost of new resource procurement will not reduce the total cost. In fact, it will increase them by the interest paid on the bonds.

For these reasons, the Commission should reject parties' recommendation to increase the PD's need determination. It should instead recommend DWR consider central procurement of, at most, 1 GW of OSW only after considering updated LSE procurement statuses, as recommended in CalCCA's opening comments.[15]

II. CALWEA'S RECOMMENDATION THAT THE COMMISSION EXPLICITLY ASK DWR TO CONSIDER PROCUREMENT OF THE CADEMO PROJECT ILLUSTRATES THE NEGATIVE CONSEQUENCES OF CENTRAL PROCUREMENT AND MUST BE REJECTED

CalWEA recommends the Commission "explicitly ask DWR to consider procurement of the CADEMO project."[16] This recommendation runs directly counter to the Commission's well-reasoned intent "not to interfere with any of these efforts or penalize early action by some LSEs for some resources."[17] It also highlights exactly why CalCCA,[18] other parties,[19] and the Legislature[20] have asked the Commission to take a cautious approach to ordering central procurement. For the reasons described below, avoiding interference with LSE procurement is essential, and the Commission should reject CalWEA's recommendation to explicitly interfere.

If the Commission were to explicitly recommend DWR explore procurement of resources LSEs already have a demonstrated interest in, LSEs may become hesitant to take future proactive actions to procure in the event their procurement activities end up being for naught. In addition, when central procurement overlaps with LSE procurement, either in terms of technology or timing, the Commission introduces additional competition into a market with scarce supply. CADEMO and all other projects, whether eligible for central procurement or not, will contract with whichever entity will provide them with the best revenue opportunity. If central procurement adds extra demand for

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14 EDF Opening Comments at 2.
15 CalCCA Opening Comments at 13-15.
16 California Wind Energy Association (CalWEA) Opening Comments at 3.
17 Proposed Decision at 39.
18 CalCCA Opening Comments.
19 SCE Opening Comments at 6-8 and 9-11, CC Power Opening Comments at 6-7.
20 *AB 1373 Senate Committee on Energy, Utilities and Communications Bill Analysis* (Version Aug. 31, 2023, published Sept. 6, 2023).

resources in scarce supply that LSEs are already interested in procuring, it will unnecessarily compete with LSE procurement and drive prices up.

As the PD notes, California Community Power (CC Power) has already initiated an RFI for OSW, resulting in a memorandum of understanding (MOU) with the CADEMO project.[21] Through the MOU, CC Power "aims to learn about the drivers of key costs of [OSW] development" and "apply for grants, incentives, and other support to minimize the cost of offtake..."[22] The efforts CC Power and CADEMO will undertake are "intended to drive parties toward the potential for a power purchase agreement with the energy benefits and costs flowing to the participating CC Power member CCAs."[23] By asking the Commission to direct DWR to explore procurement of a specific resource, CalWEA's recommendation asks the Commission to disregard existing LSE procurement activities. The Commission should not introduce central procurement opportunities for resources LSEs are already considering procuring.

III. THE COMMISSION MUST REJECT PARTIES' RECOMMENDATIONS THAT PREVENT LSE PARTICIPATION IN THE PROCUREMENT REVIEW GROUP

Invenergy objects to the composition of the Procurement Review Group (PRG) recommending that instead, PRG participants may not be involved in any market activities.[24] The Commission should reject this change. It is not clear what it means to "be involved in market activities." It is also not clear that this would only include those responsible for executing transactions (i.e., those negotiating contracts) or if it would expand to personnel working in spaces related to markets, such as legal staff or regulatory staff that regularly engage in rules governing bilateral and organized CAISO markets. The Commission's objective is to have personnel with sufficient familiarity to be able to provide meaningful input to DWR on their procurement approach, process, and contract execution.[25] Invenergy's unclear "involved in market activities" definition could leave the PRG with insufficient experience.

A better model for participation in the PRG is that provided by PG&E which would:

> permit LSE representatives, including employees, contractors, and consultants, to participate in the procurement group so long as they are not "directly responsible" for discharging any LSE's role and

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[21] Proposed Decision at 25.

[22] https://cademo.net/california-community-power-x-cademo/.

[23] *Id.*

[24] Invenergy Opening Comments at 5-6.

[25] Proposed Decision at 58, "we are persuaded that LSEs should have representation on the procurement group, both because they may have expertise to bring to the table and because their ratepayers will ultimately be paying the costs of DWR's contracts."

> responsibilities with respect to procurement, sales, or portfolio management or conducting any relevant active or open solicitations for an LSE. To effectuate this, PG&E proposes that "directly responsible" be defined as follows: the person's role involves making formal recommendations to Executives/Officers or a governing board of the LSE or direct decision-making authority regarding procurement or sales or development of strategies for active management of the LSE's portfolio.[26]

IV. PARTIES' COMMENTS AFFIRM THAT A FUTURE TRACK OF THIS PROCEEDING TO DISCUSS COST ALLOCATION IS WARRANTED

The PD rules in favor of SCE's proposal to allocate EGS and OSW on the basis of energy load share served among LSEs.[27] PG&E commented, "the Proposed Decision should be modified to correct inconsistencies between the new statewide NBCs and to ensure feasible implementation. Specifically, for energy-producing resources, the PD states that the allocation of costs be "done at the individual LSE level, without the need to allocate by IOU TAC area first."[28]

While CalCCA understands the concerns expressed by PG&E, the current PD does not require modification as the PD already states, "Further implementation details to operationalize this policy may need to be addressed by the Commission in this proceeding prior to or during consideration of actual projects to be contracted by DWR."[29]

CalCCA notes that within proceeding R.23-01-007, to implement the extension of operation of Diablo Canyon, the investor-owned utilities (IOU), CCAs, and ESPs are currently working together to develop a methodology to allocate the green-house gas-free attribute on an energy basis throughout the entire state consistent with the allocation of costs that are allocated to all LSEs in the state. This PD should not foreclose on the options that the Commission will evaluate in its "further implementation details." Since the state has rarely done any procurement for the benefit of all customers across all three IOU areas in the past, more time is needed to evaluate the best solutions to the issues once more record has been developed.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

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[26] PG&E at 10-11 (footnote omitted).
[27] Proposed Decision at 55.
[28] PG&E Opening Comments at 13-14 (footnote omitted).
[29] Proposed Decision at 55.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING TRACK 2 SCHEDULE

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SUMMARY OF RECOMMENDATIONS

- Revisit changes to the Planning Reserve Margin (PRM) level when the California Public Utilities Commission's (Commission) tools and approach are stable;
- Align the Commission's framework with the primary questions of the Resource Adequacy (RA) program;
- Maintain an annual PRM until the Commission's study methodology is sufficient to evaluate monthly or seasonal PRMs;
- Incorporate uncertainty of load forecast, based upon observed Integrated Energy Policy Report forecast errors, into the Strategic Energy Risk Valuation Model forecast error parameters;
- Ensure the contribution of storage to reliability is consistently represented;
- Evaluate whether the Commission's choice to stress the system with flat load materially impacts the PRM result;
- Refrain from repurposing or dismantling the local RA central procurement entity (CPE) at this time;
- Do not shift the CPEs' role to a backstop role at this time;
- Reject Western Power Trading Forum's proposal to shift the CPEs' role to a backstop role at this time;
- Reject Middle River Power LLC's proposal to direct CPEs to terminate contracts;
- Reject Pacific Gas and Electric Company's and Southern California Edison Company's proposals for modifying the self-showing process; and
- Work with California Independent System Operator Corporation to determine how best to harmonize local RA requirements with slice-of-day.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING TRACK 2 SCHEDULE

California Community Choice Association[1] (CalCCA) submits these Opening Comments pursuant to the *Administrative Law Judge's Ruling Modifying Track 2 Schedule*[2] (Ruling), dated June 26, 2024. The Ruling seeks comments on all proposals filed.

I. INTRODUCTION

CalCCA appreciates the efforts of Energy Division staff to develop its Loss of Load Expectation (LOLE) Study[3] and Central Procurement Entity (CPE) Report[4] and the efforts of parties to advance thoughtful proposals for Track 2 scope items. The LOLE Study, specifically

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

[2] *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, Rulemaking (R.) 23-10-011: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K332/534332050.PDF.

[3] *Administrative Law Judge's Ruling on Energy Division's Loss of Load Expectation Study*, R.23-10-011 (July 22, 2024) (LOLE Study): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=536273741.

[4] *Administrative Law Judge's Ruling on Energy Division's Central Procurement Entity Framework Report*, R.23-10-011 (June 5, 2024) (CPE Report): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K113/533113457.PDF.

the slice-of-day (SOD) planning reserve margin (PRM) calibration, is undergoing additional updates and parties will have an opportunity to comment at a later date.[5] CalCCA looks forward to reviewing the updated SOD PRM calibration and commenting on the results at that later date. These comments focus on the study methodology presented at the July 25, 2024, workshop and recommend improvements to that methodology.

The California Public Utilities Commission (Commission) should focus on "[r]etain[ing] the CPE Framework with modifications to address known issues,"[6] in this track of the proceeding rather than attempting to "repurpose" or "dismantle" it. The Resource Adequacy (RA) program is in the process of a significant transition with the implementation of the SOD RA program. The Commission should not contemplate one significant change to the RA program while it has yet to complete another. In this track, the Commission should focus on ways to improve the interactions between the CPE and load-serving entities (LSE) by increasing the certainty LSEs have about their own procurement obligations well in advance of their compliance deadlines.

CalCCA offers the following comments to the LOLE Study and parties' Track 2 Proposals[7] aimed at achieving these objectives:

- Revisit changes to the PRM level when the Commission's tools and approach are stable;
- Align the Commission's framework with the primary questions of the RA program;
- Maintain an annual PRM until the Commission's study methodology is sufficient to evaluate monthly or seasonal PRMs;

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5 LOLE Study.
6 CPE Report at 54.
7 References to Track 2 Proposals refer to those filed in R.23-10-011 on June 14, 2024.

- Incorporate uncertainty of load forecast, based upon observed Integrated Energy Policy Report (IEPR) forecast errors, into the Strategic Energy Risk Valuation Model (SERVM) forecast error parameters;
- Ensure the contribution of storage to reliability is consistently represented;
- Evaluate whether the Commission's choice to stress the system with flat load materially impacts the PRM result;
- Refrain from repurposing or dismantling the local RA CPE at this time;
- Do not shift the CPEs' role to a backstop role at this time;
- Reject Western Power Trading Forum's (WPTF) proposal to shift the CPEs' role to a backstop role at this time;
- Reject Middle River Power LLC's (MRP) proposal to direct CPEs to terminate contracts; and
- Reject Pacific Gas and Electric Company's (PG&E) and Southern California Edison Company's (SCE) proposals for modifying the self-showing process;
- Work with the California Independent System Operator Corporation (CAISO) to determine how best to harmonize local RA requirements with SOD.

II. LOLE RECOMMENDATIONS

A. Revisit Changes to the PRM Level When the Commission's Tools and Approach are Stable

The Commission is continuing to identify necessary changes to the SOD PRM calibration tool, calling into question the recommended PRM put forth in the LOLE Study. In addition, CalCCA suggests several changes or alternatives in the comments below. It is premature to change the PRM while the tools and approach are being revised and vetted by stakeholders. The RA program is already undergoing a major transition from the peak-hour to SOD framework. Major changes to the level of the PRM only make sense once the Commission's tools and approach and this new framework has been implemented, tested, and proven successful.

B. Align the Commission's Framework with the Primary Questions of the RA Program

The Commission's process for making a PRM recommendation follows the following steps:

1) Identify the baseline set of resources expected to be available in 2026 (Baseline),

2) Evaluate the reliability of the baseline portfolio in SERVM,

3) Calibrates the baseline portfolio to meet the 0.1 LOLE target (Calibrated Baseline),

4) Apply the SOD accreditation rules to the resources in the Calibrated Baseline portfolio,

5) Use the accredited supply to calculate the reserve margin in each hour and month,

6) Finds the amount of additional flat load the Calibrated Baseline portfolio can accommodate before the hour with the lowest reserve margin matches that found in the highly constrained month of September, and

7) Use SERVM to validate that the Calibrated Baseline portfolio is able to meet the demand plus additional flat load in each month with an adequate level of reliability.

The logical connection between this process and the objectives of the Commission's RA program is not obvious and easy to follow. The Commission's monthly RA program allocates the forecasted 1-in-2 peak demand to LSEs and then asks LSEs to show contracts with resources that, when accredited based on the SOD rules, meet or exceed their share of the allocated demand and a PRM. The primary question of the RA program is therefore: If LSEs show resources that, using the SOD accreditation rules, meet their share of the demand and PRM, will the resulting system be reliable? The process for setting the PRM and accrediting resources in the SOD framework should be organized and flow from this primary question.

C. Maintain a Single Annual PRM Until the Commission's Study Methodology is Sufficient to Evaluate Monthly or Seasonal PRMs

The Commission's current process sets a target annual PRM at the lowest level of reserves in the Calibrated Baseline relative to the 1-in-2 peak day demand. The Commission then finds the increase in the flat load that causes the lowest reserves in each month to match the target annual PRM. The Commission uses SERVM to verify that the Calibrated Baseline with the additional flat load still achieves a reliability level of LOLE equal to 0.1.

Missing from this current methodology is as characterization of the variability and uncertainty of the system that would warrant monthly or seasonal variation in the PRM rather than an annual PRM. The Commission should not accept proposals[8] for a monthly or seasonal PRM until the Commission's methodology is revised to evaluate the advantages and feasibility of such a shift.

To consider a monthly or seasonal PRM, the Commission's methodology would need to include the following elements. It would need to characterize variability in peak demand around the 1-in-2 peak day for each month. Until an unforced capacity accreditation is in use, the Commission's methodology would also need to evaluate monthly and seasonal differences in supply variability. The methodology would need to consider the economic efficiency of varying PRMs. Finally, the methodology would need to ensure that the generation resources needed to meet each month's PRMs have sufficient opportunity for planned outages. If the PRM is too high in low-demand months, all resources may need to be shown, eliminating opportunities for maintaining the generation fleet and adversely impacting reliability.

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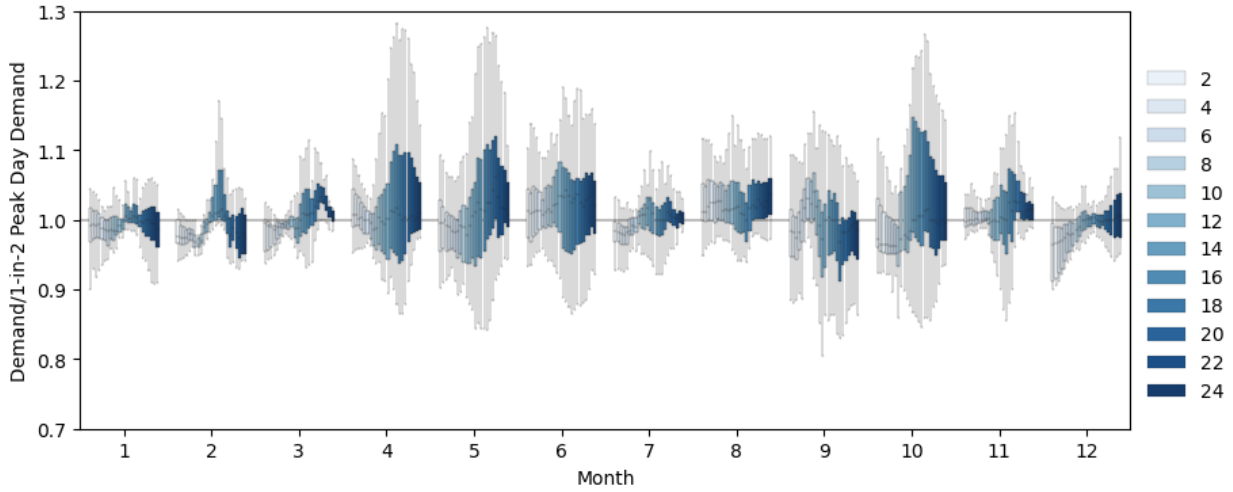
[8] American Clean Power-California Track 2 Proposals at 3.
Track 2 Proposals of Vistra Corp at 4-6.

CalCCA provides the following analysis to illustrate how the Commission could modify the study methodology to evaluate differences in monthly demand variability that would be the basis for monthly PRMs. CalCCA used the 23 weather years of consumption data from the Commission's 2023 System Modeling Datasets[9] to show how peak day demand varies across weather years from the 1-in-2 peak day demand used to set RA requirements. Figure 1 shows the distribution of the hourly demand on peak days in each month relative to the 1-in-2 peak day demand in each month. The variation in peak day demand around the 1-in-2 peak demand is largest for April, May, June, September, and October. The variation is distinctly smaller in January, February, March, and July. This is the type of analysis required to suggest that a monthly PRM would differ to account for greater variability of peak demand around the 1-in-2 peak demand in some months compared to others. The Commission would need to use a similar analysis to justify a PRM that varies from month to month rather than a single annual PRM.

Figure 1. Variation in Peak Demand Across Weather Years Relative to 1-in-2 Peak Demand for Each Month



[9] Analysis is based on the Commission's Hourly Consumption Demand (all regions, all weather years, Monday start) for 2026 from the System Reliability Modeling Datasets 2023 at https://files.cpuc.ca.gov/energy/modeling/2023PSP/LoadProfiles_AllRegions_MondayStart.zip.

D. Incorporate Uncertainty of the Load Forecast, Based on Observed IEPR Forecast Errors, into SERVM Forecast Error Parameters

The Commission identifies a gap between the IEPR forecast used to set the SOD PRM and the IEPR forecast used to set the RA load requirements and asks how best to address this gap. Differences in the IEPR 1-in-2 load forecast and the actual 1-in-2 weather year should be accounted for in reliability assessments and PRM setting. The Commission's SERVM model includes a load forecast error parameter that can be used to account for non-weather related load forecast errors.[10] However, CalCCA has pointed out in previous comments[11] that the economic load forecast error used in SERVM is derived from a European Central Bank survey of professional forecasters, rather than California's experience forecasting the 1-in-2 peak load. The Commission should consider using load forecast errors from historical IEPR forecasts.

E. Ensure the Contribution of Storage to Reliability is Consistently Represented

The SOD accreditation of storage in the Commission's process is a critical piece of setting the PRM to ensure reliable portfolios. The accreditation of storage should be consistent with the capabilities of storage represented in SERVM. The Commission should validate the dispatch of the SOD PRM Tool by comparing the storage dispatch in the tool to the SERVM dispatch on days with loss of load, particularly in the highly constrained month of September.

F. Evaluate Whether the Commission's Choice to Stress System with Flat Load Materially Impact PRM Results

The Commission's approach includes a choice to add flat load to each month to bring the reserves shown by the Calibrated Baseline to the annual PRM target level. Adjusting portfolios

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[10] California Public Utilities Commission. *Proposed Inputs & Assumptions: SERVM 2024 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)* at 7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K361/527361341.PDF.

[11] *California Community Choice Association's Informal Comments on the Draft Inputs and Assumptions (2023 I&A)* at 4: https://cal-cca.org/wp-content/uploads/2023/07/Final-Informal-Commentson-Draft-2023-IA-Document-06-21-23.pdf.

by adding perfect capacity resources or flat load (i.e., negative generators with zero forced outage rates) are used as proxies in reliability studies by other jurisdictions, including the Midwest Independent System Operator.[12] However, given the PRM is intended to capture resource and demand volatility, simply adding flat loads may not be sufficient to assess actual resource needs in a specific month. Choosing these perfect capacity or flat loads may have material impacts in the Commission's unique SOD framework relative to other options. For example, adding flat load disproportionally reduces the availability of excess resources to charge storage in the off-peak hours. Alternatives such as scaling load by the same percentage in all hours or scaling the entire baseline portfolio should be evaluated by the Commission to demonstrate that PRM results are insensitive to the choice of approach.

III. CPE RECOMMENDATIONS

A. Refrain from Repurposing or Dismantling the Local RA CPE at this Time

Several parties advance proposals to repurpose the CPE framework to procure and plan for gas retirements or dismantle the CPE framework. The Commission should not repurpose the CPE within Track 2. Repurposing the CPE in Track 2 to procure and plan for gas retirements would rush to a solution that does not holistically consider the need. Planning for local gas retirements requires an assessment of generation and transmission to determine the optimal path forward for reducing reliance on natural gas; either by developing new clean resources in the local area or developing transmission to reduce the local area constraints.

While PG&E supports establishing a centralized planning and procurement process to reduce reliance on natural gas, PG&E rightly notes, "[b]ecause local capacity areas are

[12] Midcontinent Independent System Operator. *Planning Year 2023-2024 Loss of Load Expectation Study Report* at 33: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

transmission-constrained, it is important that [a centralized planning and procurement] process and structure consider both transmission-based and supply-based solutions; however, these trade-offs cannot be solely captured and determined within the RA proceeding and the development of a process will also require coordination with the IRP proceeding and CAISO's TPP..." [13] Without coordination with the IRP and TPP processes first, the Commission cannot determine that centralized procurement through the local RA CPE is the most efficient, cost-effective way to reduce reliance on natural gas in local areas.

As California Energy Storage Alliance (CESA) states, there is a risk that "... repurposing the CPE framework would result in retention of existing natural gas plants, rather than holistically capturing the procurement that is needed to meet reliability needs and California's clean energy goals, as would be done through the IRP process."[14] Rather than repurposing the CPE, the Commission should develop a process within the IRP proceeding that evaluates the generation and transmission solutions needed to reduce reliance on local gas-fired resources.

The Commission should also refrain from contemplating dismantling the CPE at this time. The Commission is currently in the process of transitioning from the peak-hour RA program to the hourly SOD RA program. The Commission should not contemplate a new significant change to the RA program until the SOD program has been implemented, tested, and proven successful. This is especially true because the local RA CPE itself has only had local RA requirements for the last two years, and the Commission and parties are only now conducting a comprehensive review of the effectiveness of the local RA CPE framework.

The constant shifting of LSE compliance frameworks, rules, and obligations makes it difficult for the market to adjust and settle into changes as they occur. While broader structural

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[13] PG&E Track 2 Proposals at 9-11.

[14] CESA Track 2 Proposals at 4.

changes to the CPE framework may be beneficial or necessary, developing and adopting them now could do more harm than good, given the state of the RA market today and the transitions already in progress. Retaining the CPE framework with modifications to address known issues will allow RA market participants to focus on adjusting to changes already in progress. Once the RA market calms and the Commission has fully transitioned to its permanent system RA framework, the Commission can consider broader structural changes to the CPE framework.

B. Do Not Shift the CPEs' Role to a Backstop Role at this Time

WPTF proposes that "the Commission retain the CPE framework while refocusing CPE procurement on local resources that are needed to meet local reliability requirements and have not been contracted by LSEs to meet system RA requirements. In other words, the CPEs would be limited to a backstop procurement role aimed at addressing any residual local capacity needs."[15] WPTF's proposal "would depend in part on the adoption of multi-year forward procurement requirements for LSEs."[16] Given that multi-year forward RA requirements are not in the scope of Track 2, WPTF recommends the Commission defer consideration of proposals to repurpose or dismantle the CPE in parallel with the Reliable and Clean Power Procurement Program (RCPPP).

The Commission should not consider modifying the CPE's role to a backstop role at this time. CalCCA agrees with WPTF that proposals to modify the CPE's role should be considered in alignment with the RCPPP. This will ensure a comprehensive and coordinated approach to ensuring the retention of existing resources needed for reliability. In addition, RA prices are

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[15] WPTF Track 2 Proposals at 10.

[16] *Id.* at 11.

currently at all-time highs.[17] While multi-year RA may be one way to ensure the retention of existing resources, rushing to adopt multi-year forward RA requirements for LSEs now will ensure high-price contracts are locked in for multiple years forward, exacerbating the ongoing affordability crisis facing the state's customers. For these reasons, the Commission should defer consideration of proposals contingent on multi-year system RA at this time.

C. Reject MRP's Proposal to Direct CPEs to Terminate Contracts

MRP proposes the Commission "authorize and require the CPEs to terminate CPE capacity contracts to allow that capacity to be transferred to another LSE when that LSE elects to procure directly with the resource owner for a long-term contract, identified as five (5) years or greater, and such contract has a delivery period that is overlapping with the existing CPE contract." [18] The purchasing LSE would then have an obligation to self-show that capacity for the duration of the former contract with the CPE.

The Commission should not adopt MRP's proposal. MRP acknowledges "[t]his conversion from CPE-contracted capacity to self-shown capacity would affect other LSEs serving load in the same TAC area. Such LSEs would receive fewer CAM credits during the same period."[19] While MRP suggests giving LSEs notice of transfers by June 30 prior to the compliance year would give LSEs "some level of volumetric certainty" of their CPE allocations, MRP's proposal would exacerbate existing challenges LSEs face with predicting their allocations. As a result of this proposal, the allocations that LSEs expect to receive after procurement for the CPEs' two-year ahead and three-year ahead requirements could decrease or

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[17] *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs* (updated Jan. 16, 2024) at 9-11: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf.

[18] MRP Track 2 Proposals at 13.

[19] *Id.* at 16.

be taken away entirely, significantly impacting LSEs' ability to plan for their own system and flexible RA requirements.

This proposal will not result in reliability or affordability benefits to justify such added uncertainty. Transferring CPE procurement does not increase the amount of capacity under contract for the Commission's RA program. It simply transfers the costs and benefits LSEs would already pay for collectively to an individual LSE, or LSEs. The MRP proposal would allow generators to abandon relatively low-priced contracts with the CPE, who can defer procurement to backstop if prices are too high, for higher ones with LSEs, who cannot defer their procurement due to high costs. For these reasons, the Commission should decline to require the CPE to terminate contracts for resources individual LSEs want to procure.

D. Reject PG&E and SCE's Proposals for Modifying the Self-Showing Process

SCE and PG&E propose changes to the process LSEs use to voluntarily "self-show" local capacity they have under contract to the CPEs. The existing self-showing process allows LSEs to voluntarily self-show capacity to the CPE. In some cases, LSEs will receive compensation for self-showings via the local capacity reduction compensation mechanism (LCR-RCM). These cases are limited, however, as the LCR-RCM only applies to preferred resources and energy storage and only results in payment when the local RA premium is greater than zero.[20] LSEs take on risks and lose flexibility in their portfolio by self-showing which likely prevents LSEs from doing so, especially given the limited incentives to self-show.

SCE proposes that the Commission "require LSEs who plan to include system resources located in a local area toward their system RA requirements to self-show that resource earlier

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-2024.pdf.

than the October year-ahead system filings."[21] SCE suggests that its proposal would "reduce the amount of local RA the CPE is required to procure, which would reduce RA costs included in customers' rates."[22] The Commission should not adopt SCE's proposal. "Forcing" LSEs to self-show ignores the inherent risks associated with self-showing. SCE asks that the Commission force LSEs to make decisions about their portfolios prior to the current deadlines. As CalCCA has previously pointed out, self-showing is not risk free. Those that self-show reduce portfolio flexibility in selling portions of their portfolio or potentially taking planned resource outages. Effectively, SCE is asking that LSEs perform their procurement and self-show, turning the CPE into a backstop entity for local rather than have the primary responsibility for local area procurement. CalCCA's modified CPE timeline proposal is a better way to manage local RA costs because, rather than requiring LSEs to take on risks involuntarily, it would allow LSEs to do their procurement with an understanding of the allocations it will receive from the CPE. This will reduce the need for LSEs to over-procure to manage the uncertainty associated with allocations that come after the LSE does its own procurement.

PG&E proposes to eliminate the self-showing process in favor of a process for "CPEs to collect information directly from Energy Division regarding local RA capacity that is already under contract with LSEs."[23] The information Energy Division would collect from LSEs would include: resource ID, local area, contract start and end date, technology type, and contracted MW. The Commission should not adopt PG&E's proposal. While the proposal intends to give the CPE more information to use in its procurement decision-making processes, it is unclear what purpose having this information would serve. If the information is intended to indicate

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[21] SCE Track 2 Proposals at 3.
[22] *Id.*
[23] PG&E Track 2 Proposals at 6.

which resources may be unavailable for CPE procurement, the CPE will know such information after those resources are not offered into its solicitations. Additionally, it is not possible to use this information to understand which resources may be offered into its solicitations or shown for system RA. If a resource is not under contract by an LSE, it does not imply that it will be available for CPE procurement. It could be under contract by a non-Commission jurisdictional LSE or out-of-state entity. If a resource is under contract by an LSE, it does not imply that it will be shown for system RA. It may be held for substitution or sold to another LSE. Finally, the LSE may themselves offer it to the CPE as a local RA sale. If PG&E knows that the resource is under contract to an LSE, they would likely forego procuring the resource for local RA, defeating the original design which allows any entity to offer to sell local RA to the CPE with equal opportunity of being procured.

Given the usefulness of the CPE having this information is questionable, the Commission should refrain from adopting this proposal to avoid the adverse impacts it could have on LSE procurement activities. PG&E's proposal would provide one procuring entity (the CPE) with more information than other procuring entities (LSEs). In addition, it is not clear that the existing firewalls in place to separate the IOUs' CPE functions and LSE functions are sufficient to ensure the IOUs do not have a competitive advantage over LSEs. CalCCA's proposal to revise the CPE timeline would avoid these concerns and result in more efficient local *and* system RA procurement because it would reinstate a sequential procurement process in which LSEs know their CPE allocations prior to its year-ahead system RA procurement processes.

For these reasons, the Commission should forego the recommendations of SCE and PG&E and instead adopt CalCCA's proposal to modify the timeline to allow the CPE to complete its procurement after its two-year ahead procurement process. This proposal would

result in more efficient local and system RA procurement processes and contain RA costs by providing LSEs certainty around their CPE allocations and thus preventing the need to over procure to mitigate the risk of unknown CPE allocations.

E. Work with the CAISO to Determine How Best to Harmonize Local RA Requirements with SOD

SCE proposes to "shift local RA requirement setting from the Effective Load Carrying Capacity-based Net Qualifying Capacities to incorporating peak hour values of the month from energy sufficiency profiles…" to "harmonize the methodology for showings for the CPE local RA and system [SOD] frameworks."[24] CalCCA supports additional consideration of the right ways to harmonize the local and system RA programs. Given the differences in requirement setting for local RA and system RA, the Commission should work with CAISO to determine how best way to do so.

Unlike system RA requirements, which are primarily driven by 1-in-2 load, local RA requirements are driven by transmission contingencies under 1-in-10 load. Thus, it is likely not necessary to develop hourly local RA requirements like those adopted for system RA, but it may be necessary to revise the resource values used for local RA to align with those used for system RA. The CAISO should inform the Commission of its assumptions used for variable resources and storage in its local capacity technical study and inform the right way to harmonize local and system RA.

[24] SCE Track 2 Proposals at 3.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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

August 9, 2024

California Community Choice Association

SUBMITTED 08/08/2024, 02:07 PM

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

1. Please provide a summary of your organization's general comments on the Issue Paper & Straw Proposal (IPSP) and the stakeholder meeting.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) storage bid cost recovery (BCR) and default energy bids (DEB) enhancements workshop. CalCCA agrees with the CAISO that the BCR framework should not disincentivize consideration of real-time conditions and should not present opportunities for pursuing unwarranted revenue. The pace the CAISO intends to conduct this initiative, however, does not allow the time necessary to develop a robust solution to the complex problem of accurately determining when BCR is warranted or unwarranted.

The CAISO proposes to reclassify energy associated with state of charge (SOC) constraints during the binding interval as non-optimal due to physical limitations A blunt mechanism to addressing some portion of BCR payments being unwarranted, like the CAISO's proposal, does not account for the fact that legitimate cost-based bids into the real-time market may result in the dispatch of storage in a manner that results in buy-backs or sell-backs and accruing BCR.

As discussed in CalCCA's July 18, 2024, comments,[1] excluding storage from BCR in most instances is too blunt of a mechanism to be the permanent solution but the pace of this initiative may be too quick to develop something more robust. The CAISO's Track 1 proposal should be a temporary solution only. The CAISO must commit to beginning an initiative immediately following Track 1 to develop a more comprehensive solution to unwarranted BCR payments that considers (1) the drivers of BCR payments (e.g., resource operator action to trigger BCR payments or CAISO market dispatch), and (2) necessary enhancements to the storage market model more broadly.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/f7f6fb35-66cd-4279-821d-8711799e4468#org-37ce3de3-fe23-4352-b48c-28724ba3e358.

2. Please provide your organization's comments regarding the framing, scope, and schedule of the initiative as stated in the IPSP (Sections 1 and 2).

See response in Section 1. Again, the timing for Track 1 is likely untenable to come to an effective resolution that addresses unwarranted storage BCR. It does not allow sufficient time for the CAISO to analyze the driver of BCR payments, whether those payments are warranted or unwarranted, and the magnitude of such payments. The CAISO should view any measures adopted in Track 1 as temporary until the CAISO and stakeholders can develop a more robust solution promptly following the conclusion of Track 1.

3. Please provide your organization's comments regarding the issue of unwarranted storage BCR and the examples included in the IPSP (Sections 3.1 and 3.1.1).

See response in Section 1.

4. Please provide your organization's comments regarding the issue of BCR provisions for energy storage in co-located configurations as stated in the IPSP (Section 3.2).

CalCCA has no comments at this time.

5. Please provide your organization's comments regarding the estimation of opportunity costs within the storage Default Energy Bid (DEB) as stated in the IPSP (Section 3.3).

CalCCA has no comments at this time.

6. Please provide your organization's comments regarding the proposal to reclassify energy associated with SOC constraints during the binding interval as non-optimal due to physical limitations (Section 4).

See response in Section 1.

7. Please provide your organization's comments regarding the proposed governance classification as stated in the IPSP (Section 5).

CalCCA has no comments at this time.

8. Please provide any additional comments, feedback, or examples regarding the IPSP and the stakeholder meeting. You may upload examples or data using the "Attachments" field below.

CalCCA has no additional comments at this time.

California Community Choice Association

SUBMITTED 08/12/2024, 03:04 PM

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

1. **Please provide a summary of your organization's overall comments on the Resource Adequacy Modeling and Program Design (RAMPD) Revised Discussion Paper and Final Recommendation Plan posted on July 26, 2024.**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) RAMPD Revised Discussion Paper and Final Recommendation Plan. CalCCA generally supports the Revised Discussion Paper and Final Recommendation Plan with respect to the three tracks moving forward to policy development and the problem statements for those tracks. Its primary concerns with the CAISO's updated path forward for tracks 2 and 3 are:

- The CAISO should not shift the resource adequacy (RA) program from monthly showings to annual showings.
  - As described in CalCCA's May 27, 2024, comments,[1] the CAISO should not shift the RA showing granularity from monthly to yearly because there is less certainty of the availability of certain resources (primarily hydro and imports) in the year-ahead time frame than in the month-ahead time frame.
- The CAISO should not include a planned outage buffer in the PRM.
  - As described in CalCCA's May 27, 2024, comments,[2] the CAISO should not consider a planned outage buffer as doing so would shift the burden of generator outages from the party that can control outages (the generator) to a party that cannot (the load-serving entity (LSE)).
- The CAISO should not link the capacity procurement mechanism (CPM) Soft Offer Cap (SOC) to bi-lateral market prices.
  - As described in CalCCA's July 2, 2024, comments,[3] the lack of Clean System Power (CSP) offers is not a function of the way the CAISO's current backstop processes are designed but rather a function of the current lack of capacity that has RA market prices unprecedentedly high. This does not signal a need to change the current CPM SOC. The process for defining the SOC works as intended, covering going-forward fixed costs of the marginal resources on the system and mitigating market power while allowing a generator that can demonstrate higher costs to recover those costs. It is not intended to be competitive with bi-lateral market prices, which currently reflect market scarcity rather than resources' costs.

CalCCA supports exploring the other elements of the CAISO's updated path forward for tracks 1, 2, and 3 and looks forward to continuing to engage in the policy development phase of this initiative.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/a79881e1-374a-4d13-aa17-cbbf7e631b3a#org-6b240e6d-295e-4f19-9bf2-280896d7b4a4.

[2] *Id.*

[3] https://stakeholdercenter.caiso.com/Comments/AllComments/10d5fec5-8032-43e4-aa30-067535d504e8#org-52666ab8-09fa-4ee9-8b71-00cbb97ea0b9.

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
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August 21, 2024

Advice Letter 79-E/E-A

Amulya Yerrapotu
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: ayerrapotu@mcecleanenergy.org

SUBJECT: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Dear Amulya Yerrapotu:

Marin Clean Energy Advice Letter 79-E/E-A is effective as of August 7, 2024.

Sincerely,

Leuwam Tesfai
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division
California Public Utilities Commission

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	Docket No. ER24-2671-000

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION'S TARIFF AMENDMENT TO IMPLEMENT TRACK 2 OF INTERCONNECTION PROCESS ENHANCEMENT 2023 INITIATIVE

Pursuant to Rule 211 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure,[1] 18 C.F.R. Section 385.212 (2023), the California Community Choice Association[2] (CalCCA) submits these comments to the California Independent System Operator Corporation's (CAISO) *Tariff Amendment to Implement Track 2 of Interconnection Process Enhancements 2023 Initiative*[3] (Tariff Amendment), dated August 1, 2024. The Tariff Amendment seeks to implement reforms essential for the CAISO to adapt to the dramatically increased levels of requests to interconnect to the CAISO-controlled grid.

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[1] Federal Energy Regulatory Commission's Rules of Practice and Procedure, Part 385.

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

[3] California Independent System Operator Corporation's *Tariff Amendment to Implement Track 2 of Interconnection Process Enhancements 2023 Initiative*, ER24-2671-00 (Aug. 1, 2024).

I. INTRODUCTION

CalCCA is a trade association representing the interests of 24 community choice aggregators (CCA) in California. CalCCA's membership serves over 14 million customers in over 200 cities and counties throughout the state, representing roughly one-third of the CAISO load in California. As load-serving entities (LSE) actively procure new electric generating resources to serve California customers, California CCAs have a direct interest in ensuring an efficient and effective interconnection process that supports the accelerated pace of clean energy resource development. CalCCA requests the Commission accept the CAISO's Tariff Amendment, which makes meaningful improvements to the CAISO's ability to support the pace of interconnection necessary to achieve California's policy and reliability needs.

II. COMMENTS

CalCCA respectfully asks that the Commission accept the CAISO's Tariff Amendment. The Tariff Amendment comes at a critical point when procurement activities have expanded at a rapid pace to maintain reliability targets while meeting California's clean energy policies, like Senate Bill (SB) 100 (De León).[4] CalCCA estimates that to reach SB 100 targets on schedule, California will need over 6,000 megawatts of new resource interconnection per year from 2024 to 2045, an increase in the annual net growth rate by roughly 400 percent relative to the net growth rate from 2001 to 2023.[5] While the entire industry is moving as quickly as possible to bring new

[4] SB 100 requiring renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045.

[5] 2001-2022 Electric Generation Capacity and Energy, California ISO 2023Year in Review less 2023 retirements list, and SB100 Joint Agency Report (assumes straight line growth between 2024 and 2045).

clean resources online, policies and processes need to evolve to accommodate the unprecedented pace of procurement that will continue as California progresses toward its SB 100 goals.

The Tariff Amendment advances much-needed transformations to the interconnection cluster study and queue management processes while maintaining open access to the transmission system. It intends to prioritize interconnection requests by ranking requests within available transmission zones based on indicators of readiness; commercial interests, project viability, and system needs. It also recognizes the importance LSE interest will play when narrowing down the pool of interconnection study requests. LSEs, as procuring entities, conduct long-term planning activities in their individual integrated resource plans, where they start to identify the technologies, locations, and magnitudes of projects they will pursue to support the communities they serve. LSEs must procure a variety of technologies to achieve both reliability and greenhouse gas reductions in a cost-effective manner that meets their customers' needs, and in the case of some LSEs like CCAs, complies with their governing boards' mandates. This procurement activity is factored into the California Public Utilities Commission's preferred system plan, which then informs the CAISO's transmission planning process.

Without an LSE interest-scoring criterion, the CAISO would risk having an interconnection queue that is not aligned with resource and transmission planning processes taking place in these forums. Given that reliability depends critically on having the right mix of resources on the grid, this alignment with planning is fundamentally

important to CAISO's operations. CalCCA agrees with the CAISO that the commercial interest category is:

> ...a critical piece of the tariff reforms proposed in this filing. Given the LSEs' essential role in resource procurement under California state law and the Commission-approved resource adequacy provisions of the CAISO tariff, LSE interest is a key indicator of commercial interest and the ultimate viability of a generation project seeking interconnection. Awarding points for commercial interest will allow the CAISO to remove speculative projects not likely to be viable earlier in the interconnection process and provide a useful metric in determining whether a project is ready for study.[6]

CalCCA supports the CAISO's objective of a robust, fair, and transparent point allocation process, and appreciates the CAISO's Track 2 Final Addendum which (1) provides requirements for opting into the allocation process, publicly posting selection criteria, and acting in a non-discriminatory manner, and (2) strongly encourages incorporating best practices into the LSE allocation processes.[7] CCAs are committed to making the LSE point allocation process as transparent and fair as possible. CCAs intending to participate in the allocation process are committed to taking the CAISO's encouragement to "conduct public requests for information, requests for offers, or some other functionally equivalent process to ensure fairness, transparency, and competition in the LSE allocation process."[8] They are also open to continuing to work with the CAISO and developers to improve the LSE point allocation process as LSEs, the CAISO, and developers gain experience with the new interconnection study process.

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[6] Tariff Amendment at 49.

[7] *Id.* at 49-50.

[8] *Id.* at 50: https://statics.teams.cdn.office.net/evergreen-assets/settings/window-mode/window-mode-coachmark.svg.

III. CONCLUSION

CalCCA respectfully requests that the Commission accept the CAISO's Tariff Amendment.

Respectfully submitted,

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

August 22, 2024

CERTIFICATE OF SERVICE

I, Shawn-Dai Linderman, hereby certify that I have this day served a true copy of **CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION'S TARIFF AMENDMENT TO IMPLEMENT TRACK 2 OF INTERCONNECTION PROCESS ENHANCEMENT 2023 INITIATIVE** by electronic mail to each party of record designated on the official service list in the above-captioned proceeding.

Executed on **August 22, 2024**, at Martinez, California.

/s/ Shawn-Dai Linderman
Shawn-Dai Linderman

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S INFORMAL COMMENTS ON THE 2025 RESOURCE ADEQUACY AND SLICE OF DAY GUIDE

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) appreciates the opportunity to comment on the *2025 Resource Adequacy and Slice of Day Guide* (2025 RA Guide), issued July 29, 2024, the Slice-of-Day (SOD) templates, and other matters related to SOD implementation. CalCCA offers the following recommendations in the comments below:

- The California Public Utilities Commission (Commission) must correct validation test errors;
- The Commission must clarify the process for adding resources to the master resource database (MRD) to count Resource Adequacy (RA) expected to come online for month-ahead filings; and
- The Commission must issue its draft and final MRDs in a timely manner.

II. COMMENTS ON THE SOD TEMPLATES

A. The Commission Must Correct Validation Test Errors

The latest version of the SOD template continues to contain issues with the flexible capacity validation test and storage excess capacity validation test. There appears to be a

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

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discrepancy between the SOD template and the template filing guide, and the template is providing incorrect validation results on the "Validation Overview" tab. For example, the equation for the flexible capacity validation test on page 23 of the template user guide clearly states that a load-serving entity's (LSE) total countable flexible capacity must be greater than the sum of its category requirements. The validation test in the template only nets an LSE's total countable flexible capacity against its flexible capacity category 2 and 3 requirements, not all three flexible capacity category requirements. As a result, the template reports that an LSE has passed the flexible capacity validation test even if their total countable flexible capacity is less than their total flexible requirement.

The storage excess capacity validation test faces similar issues. The template appears to undercount the total excess capacity needed to charge shown storage resources, resulting in the potential to falsely pass the validation test. These issues create significant uncertainty regarding how these validation tests will be measured for the 2025 year-ahead filing. While the "Profile Optimization" tab could be a valuable tool for LSEs to use to optimize the use of their storage resources in their SOD showings, LSEs continue to have issues using the profile optimization tab, limiting its use. In addition, LSEs would get the most value out of the optimizer if it were to use storage to minimize open positions, and Energy Division confirmed during the SOD Office Hours on August 16, 2024, that is not the goal of the Profile Optimization tab. Therefore, LSEs are left to manually input storage into the tool using the custom profiles tab to optimize their portfolios. This makes it especially critical that the Commission should resolve the storage

excess capacity validation test, in addition to the flexible capacity validation test, as soon as possible so that LSEs can validate 2025 positions.

III. COMMENTS ON THE MRD

A. The Commission Must Clarify the Process for Adding New Resources to the MRD to Count RA Expected to Come Online for Month-Ahead Filings

The Commission allows LSEs to show resources under construction at the time of the year-ahead filing to meet year-ahead RA obligations. The resource must then demonstrate that it is operational prior to the month-ahead filing for the LSE to use it for its month-ahead obligation.[2] It also allows resources that reach commercial operation dates between the month-ahead RA showings and the start of the RA month to count as cure capacity in the summer months.[3] The 2025 RA Guide documents the process for the latter,[4] but not the former.

To count new resources that reach commercial operation between the year-ahead and month-ahead RA processes on month-ahead RA showings, the California Independent System Operator Corporation (CAISO) requires resources to request to be moved from the "under construction" tab on the Net Qualifying Capacity (NQC) list to the main tab. The CAISO only allows resources on the main tab to count towards the monthly RA showings. The CAISO updates its NQC list monthly to reflect these new resources that come online each month on the main tab.[5] The 2025 RA Guide does not include detailed instructions on how to add these

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[2] CAISO Reliability Requirements BPM at 82.

[3] D.24-06-004, *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*, R.23-10-011 (June 26, 2024), at 32-34: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M534/K619/534619523.PDF.

[4] 2025 RA Guide at 4-5.

[5] CAISO Reliability Requirements BPM at 82.

resources to the MRD to allow RA resources that come online before the month-ahead filing to count towards an LSE's month-ahead RA requirements. Instead, the 2025 RA Guide states the MRD, "will be updated annually for deliverability and [NQC] updates."[6] The Commission should update the MRD to include the process it will use for counting new resources that come online prior to a month-ahead filing. If that process is for LSEs to add resources into the MRD tab in the showing tool, the Commission should provide specific instructions for how to enter resources so that they will flow properly through the showing tool.

B. The Commission Must Issue its Draft and Final MRDs in a Timely Manner

CalCCA appreciates the Commission's ongoing communication with stakeholders about changes to the MRD that will impact resources' final MRD values. Because the MRD is the official database of RA-eligible resources eligible and their key attributes and resources must be "fully represented" in the MRD to be used in a SOD RA showing,[7] it is imperative the Commission publish the draft and final MRDs in a timely manner. CalCCA urges the Commission to expeditiously publish the draft and final MRDs so that they are publicly available no later than their successor documents, the NQC lists, have been made publicly available. This will allow LSEs to validate their showings using final data and make any necessary adjustments resulting from that validation.

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[6] 2025 RA Guide at 21.
[7] 2025 RA Guide at 20.

IV. CONCLUSION

CalCCA appreciates the opportunity to comment on the 2025 RA Guide and urges the Commission to consider the recommendations herein.

Date: August 22, 2024

(*Original signed by*)

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING TRACK 2 SCHEDULE

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August 23, 2024

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SUMMARY OF REPLY COMMENTS

Loss-of-Load Expectation (LOLE) Study Reply Comments

- The California Community Choice Association (CalCCA) agrees with stakeholders who suggest more time and a structured process for setting the planning reserve margin (PRM);
- CalCCA supports the resource adequacy (RA) program's focus on reliability, though economic efficiency and affordability should be considered in setting PRMs;
- CalCCA agrees with stakeholders who request further clarification and analysis of the inputs and assumptions used in Strategic Energy Risk Valuation Model (SERVM) modeling;
- CalCCA supports consistency between data used in SERVM modeling, slice-of-day (SOD) PRM translation, and SOD accreditation;
- CalCCA disputes Microsoft Corporation's (Microsoft) recommendation that only the LOLE study be used in setting the PRM; and
- CalCCA encourages the development of a methodology to determine monthly or seasonal PRMs.

Local RA Central Procurement Entity (CPE) Reply Comments

- The California Public Utilities Commission (Commission) should reject Pacific Gas and Electric Company's (PG&E) proposal to provide the local RA CPEs with load serving entity procurement information in advance of its solicitations and Southern California Edison Company's (SCE) modification to the proposal;
- The Commission should dismiss parties' misguided concerns about the CalCCA CPE timeline proposal;
- CalCCA agrees with parties that the long-term local area resource transition is best addressed in the Integrated Resource Planning (IRP) proceeding; and
- The Alliance for Retail Energy Markets (AReM) should clarify how the California Independent System Operator (CAISO) would allocate local capacity procurement mechanism costs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING TRACK 2 SCHEDULE

California Community Choice Association[1] (CalCCA) submits these Reply Comments pursuant to the *Administrative Law Judge's Ruling Modifying Track 2 Schedule*[2] (Ruling), dated June 26, 2024. The Ruling seeks comments on all proposals filed.

I. INTRODUCTION

CalCCA appreciates the opportunity to reply to parties' opening comments[3] on Track 2 proposals related to the Commission's LOLE study and the local RA CPE. Parties' opening comments on the LOLE study signal the need to take more time to further evaluate the study methodology before finalizing the PRMs for 2026 and 2027. Accurate inputs and assumptions and a robust study methodology are critical to setting the PRM to meet a 1-in-10 reliability

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

[2] *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, Rulemaking (R.) 23-10-011: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K332/534332050.PDF.

[3] References to opening comments refer to those filed on August 9, 2024, in R.23-10-011.

standard. The Commission and parties should have confidence that the results will produce a 1-in-10 reliability standard, as setting the PRM too low elevates reliability risks, and setting the PRM too high jeopardizes ratepayer affordability. CalCCA looks forward to additional discussion with the Commission and parties to ensure the LOLE study and resulting PRM threads that needle.

Many parties' opening comments on the local RA CPE directionally support modifications to the existing local RA CPE framework rather than sweeping reforms to its purpose or existence. Parties disagree, however, on how to reform the existing framework. The Commission should prioritize proposals that retain the existing CPE framework, including the ability for load-serving entities (LSE) to sell to the CPE, self-show to the CPE for compensation, and provide LSEs more certainty about the allocations they will receive from the CPE.

In summary, CalCCA provides the following replies to parties' opening comments on Track 2 proposals:

<u>LOLE Study Reply Comments</u>

- CalCCA agrees with stakeholders who suggest more time and a structured process for setting the PRM;
- CalCCA supports the RA program's focus on reliability, though economic efficiency and affordability should be considered in setting PRMs;
- CalCCA agrees with stakeholders who request further clarification and analysis of the inputs and assumptions used in SERVM modeling;
- CalCCA supports consistency between data used in SERVM modeling, SOD PRM translation, and SOD accreditation;
- CalCCA disputes Microsoft's recommendation that only the LOLE study be used in setting the PRM; and
- CalCCA encourages the development of a methodology to determine monthly or seasonal PRMs.

Local RA CPE Reply Comments

- The Commission should reject PG&E's proposal to provide the local RA CPEs with LSE procurement information in advance of its solicitations and SCE's modification to the proposal;
- The Commission should dismiss parties' misguided concerns about the CalCCA CPE timeline proposal;
- CalCCA agrees with parties that the long-term local area resource transition is best addressed in the IRP proceeding; and
- The AReM should clarify how the CAISO would allocate local CPM costs.

II. LOLE STUDY REPLY COMMENTS

A. CalCCA Agrees with Stakeholders Who Suggest More Time and a Structured Process for Setting the PRM

AReM recommends that the Commission consider separating the PRM from the forthcoming Track 2 decision so that stakeholders have time to review the revised tools and analysis.[4] CAISO recommends that the current study should not be used to set the 2027 PRM.[5] CalCCA agrees with these parties. Instead of adopting the 2026 and 2027 PRM within the Track 2 decision, CalCCA recommends: (1) that the Commission adopt AReM's recommendation to consider the 2026 PRM in a later decision, and (2) that Energy Division use the current inputs and assumptions to calculate a 2027 PRM only for informational purposes to aid planners in making procurement decisions. The Commission should then set the final 2027 PRM the following year using updated inputs and assumptions.

CalCCA also supports parties' recommendations that the Commission establish a regular schedule and process for the LOLE study and PRM setting with stakeholder input.[6] A regular

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[4] AReM Opening Comments at 5.

[5] CAISO Opening Comments at 4.

[6] San Diego Gas and Electric Company (SDG&E) Opening Comments at 2-4; Calpine Corporation (Calpine) Opening Comments at 6; MRP Opening Comments at 5; and Microsoft Opening Comments at 9.

schedule and process will ensure the PRM continues to meet reliability standards as inputs and assumptions evolve while providing stakeholders sufficient opportunities to understand and vet the results.

B. CalCCA Supports the RA Program's Focus on Reliability, Though Economic Efficiency and Affordability Should be Considered in Setting PRMs

Parties ask the Commission to formally adopt a 1-in-10 LOLE reliability standard for the RA program.[7] Some of the same parties also support the continued evaluation of additional reliability metrics in the reliability studies used to set the PRM.[8]

CalCCA agrees that the primary consideration of the RA program is ensuring a reliable system and that the current industry definition of a reliable system is one that meets a 1-in-10 LOLE. However, the focus on reliability should not lose sight of the implications for affordability. The $60 million per year cost of increasing the PRM by 1 percent,[9] for example, should be justified by a corresponding decrease in the expected societal cost of power outages. With a value of lost load of $10-14/ kilowatt-hour (kWh) of unmet load found in a recent survey of California residents,[10] a $60 million per year increase in costs is warranted if it avoids at least 4,000 megawatt-hour (MWh) per year of unmet load. The Energy Division's LOLE study finds

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[7] SDG&E Opening Comments at 4-6; CAISO Opening Comments at 2; Middle River Power LLC (MRP) Opening Comments at 6; and Microsoft Opening Comments at 2.

[8] CAISO Opening Comments at 2; MRP Opening Comments at 6; Microsoft Opening Comments at 10; Calpine Opening Comments at 9.

[9] Average peak managed load across 2026 is 36,283 MW in each month (CEC IEPR 2023 Planning Forecast). Assuming CPUC-jurisdictional loads are 90% of the CAISO peak, the average CPUC peak is 32,655 MW. The incremental cost of a 1% increase in the PRM, assuming RA costs of the current market price benchmark of $15.23/kW-mo, is therefore 32,655 MW*12mo/yr*15.23/kW-mo*1000kW/MW*1% = $60 million/yr. The cost impact could be greater if scarcity in the RA market drives prices higher as the PRM goes higher.

[10] Gorman and Callaway (2024) conducted an open-ended stated-preference experiment with California residents to estimate household willingness-to-pay (WTP) to avoid outages. They calculated an average VoLL of $10–14/kWh, within the range of estimates in prior work. Gorman, W. and D. Callaway. "Do notifications affect households' willingness to pay to avoid power outages? Evidence from an experimental stated-preference survey in California." *The Electricity Journal* 37, no. 3 (2024): 107385.

that a 1-in-10 LOLE results in at most 160-492 MWh of unmet load, far below the level required to economically justify any further increase in PRM. With the current extraordinary costs for resource adequacy, changes in the PRM should be carefully substantiated.

Along with any adoption of a reliability target, the Commission should demarcate plausible conditions that are to be addressed through the PRM and extreme conditions best left to out-of-market mechanisms. For example, during the July 25 workshop, parties suggested adding the loss of imports over interties as a consideration in the LOLE study. Essentially, these parties ask for the Commission to determine a PRM needed for conditions beyond the 1-in-10 reliability standard generally supported by parties for the RA program. Adding more and more extreme planning conditions to the list of potential contingencies that could contribute to loss of load events would likely increase the PRM needed to meet the 1-in-10 LOLE standard. However, mechanisms like the Strategic Reliability Reserve are designed to maintain grid operations in conditions that go above and beyond reasonable planned conditions.[11] Incorporating the same extreme conditions when setting the PRM and when designing the Strategic Reliability Reserve risks a double hit to ratepayers, first through electricity bills and second through taxes.

C. CalCCA Agrees with Stakeholders Who Request Further Clarification and Analysis of the Inputs and Assumptions Used in SERVM Modeling

CalCCA is concerned that the high PRM found in the Commission's 2026 LOLE study and subsequent revisions to the SOD PRM Tool is, in part, due to issues with the inputs and assumptions used in SERVM modeling. CalCCA agrees with MRP that the choice of calibrating

[11] The CEC's *California Energy Resource and Reliability Outlook, 2024* notes that "…the continued development of the SRR [Strategic Reliability Reserve] ensures that programs are available for addressing reliability risks during extreme events." (at 54): https://efiling.energy.ca.gov/GetDocument.aspx?tn=258494&DocumentContentId=94524.

Commission load profiles to Integrated Energy Policy Report (IEPR) Consumption or IEPR Managed Load may have a substantial impact on the PRM.[12]

CalCCA compared the Commission's managed load profile on the peak load day for the September 2022 and August 2020 weather year to historical load profiles observed by CAISO. The Commission's managed load profiles appear to be shifted in time toward later in the day, beyond what would be expected because of BTM PV growth in 2026. Additional details of the analysis are included in the appendix. This unexpected shift should be investigated by the Commission, and the Commission should test if the same shift occurs when calibrating to the IEPR Consumption. High peak loads later in the day will likely understate the reliability contribution of the baseline resources and, as a result, overstate the PRM required to achieve the 1-in-10 reliability target.

CalCCA also agrees with the California Energy Storage Alliance (CESA) and PG&E that the process for developing storage outage rates requires further clarification.[13] Storage outage rates used in SERVM should only reflect storage plant failures, not unavailability due to state-of-charge as suggested by the CAISO Department of Market Monitoring, since SERVM presumably manages state-of-charge to dispatch storage in the model. The Commission explained in its inputs and assumptions document that because battery storage resources do not yet report to the North American Electric Reliability Corporation's Generating Availability Data System, it uses data from the CAISO's outage management system to estimate energy storage forced outage rates. Specifically, "[s]taff engaged in a series of meetings to review the CAISO curtailment outage types and natures-of-work with various stakeholders to determine which curtailments should be included in [the effective forced outage rate (EFOR)]," and provided a list of the forced outage

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12 MRP Opening Comments at 8.

13 CESA Opening Comments at 3-5; and PG&E Opening Comments at 10.

natures-of-work in its calculation.[14] The Commission, in collaboration with the CAISO, should provide increased transparency regarding the natures-of-work the Commission included in its calculation and under what conditions battery storage resources are expected to submit such outages that will impact the resources EFOR. This will ensure the calculation only includes true resource unavailability because of a forced outage rather than apparent unavailability due to the economics of CAISO market dispatch of a use-limited resource. Finally, CalCCA supports parties' requests to review the underlying data for generator outage rates and to consider seasonal forced outage rates for winter and summer in SERVM modeling.[15]

D. CalCCA Supports Consistency Between Data Used in SERVM Modeling, SOD PRM Translation, and SOD Accreditation

Several parties commented on data used in SERVM modeling, SOD PRM translation, and SOD accreditation of resources. CalCCA supports further validation and clarification of approaches used by the Energy Division. In adjusting the data and methodologies, the Commission should ensure that the revised approaches maintain consistency between SERVM modeling, SOD PRM translation, and SOD accreditation. The consequence of differences in representation in SERVM and the SOD PRM translation tool is a choice of PRM that does not achieve the intended 0.1 LOLE.

Specifically, CalCCA agrees with parties that the dispatch of storage in the SOD PRM Tool is flawed and does not maximize the reliability contribution of storage.[16] CalCCA also agrees that the storage dispatch in the SOD PRM Tool should be benchmarked to SERVM dispatch of storage to verify that the accreditation of storage is consistent with the capabilities of

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[14] *Administrative Law Judge's Ruling on Energy Division's Proposed Inputs & Assumptions*, R.23-10-011 (Mar. 18, 2024), at 34: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=527532337.

[15] Calpine Opening Comments at 3; and PG&E Opening Comments at 10.

[16] SCE Opening Comments at 5.

storage represented in SERVM.[17] Similarly, the wind and solar profiles in the SOD PRM Tool should align with the profiles in SERVM, as noted by SCE.[18]

Other parties comment on ways to better validate or improve SERVM modeling of ambient derates[19] or geothermal performance degradation.[20] CalCCA recommends that such limits on the performance and availability of resources should be addressed through SOD resource accreditation rather than the PRM where possible. Including resource performance and availability in the PRM shifts the burden of generator unavailability from the party that can control the unavailability (the generator) to the party that cannot (the LSE). This removes the incentive for generators to conduct planned maintenance at times that minimize the impact on system reliability and adds additional demand to an RA capacity market that is already scarce.

E. CalCCA Disputes Microsoft's Recommendation that Only the LOLE Study be Used in Setting the PRM

Microsoft suggests the Commission not use the SOD PRM Tool in setting the PRM and instead have the PRM come only from the SERVM LOLE study.[21] This recommendation should be rejected as it misrepresents the information produced by the LOLE study. Figure 1 illustrates the relationship between the reliability modeling in SERVM and the quantification of reserves outside of the SERVM LOLE study.

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17 The Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) Opening Comments at 10-11.

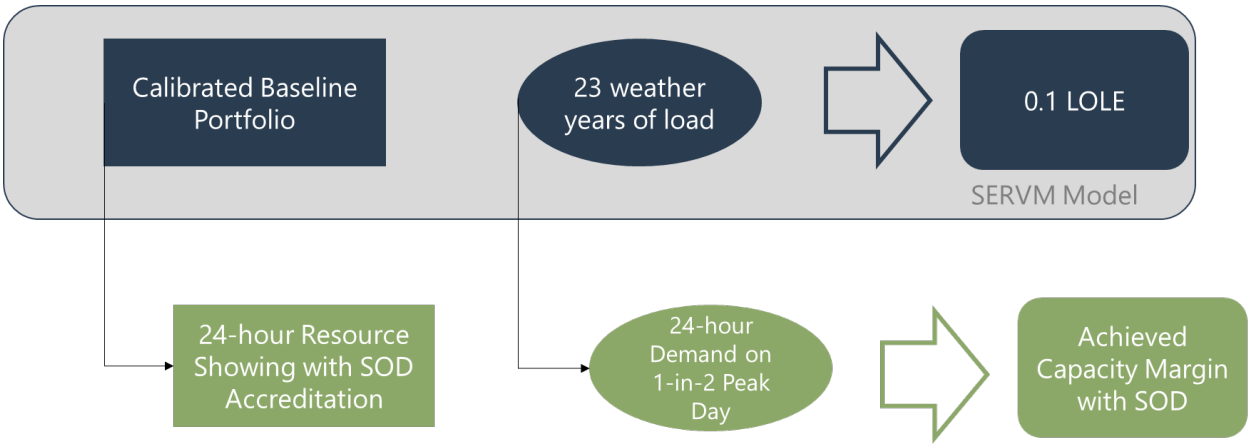
18 SCE Opening Comments at 4.

19 PG&E Opening Comments at 9; and Calpine Opening Comments at 3.

20 Cal Advocates' Opening Comments at 4.

21 Microsoft Opening Comments at 11.

Figure 1.
Quantification of Reserves Provided by the Calibrated Baseline Portfolio



In the LOLE study, SERVM is used to simulate the ability of the Calibrated Baseline Portfolio to meet hourly loads derived from 23 years of weather profiles, subject to generator outages and variability in wind, solar, and hydropower availability. The SERVM model shows that the Calibrated Baseline Portfolio is reliable in that it achieves the target 0.1 LOLE. On its own, the SERVM model does not specify or quantify planning reserves. Instead, the reserves provided by the Calibrated Baseline Portfolio are quantified outside of the SERVM model using SOD accreditation rules. The SOD PRM Tool translates the nameplate capacity of resources in the Calibrated Baseline Portfolio into a quantity of accredited supply for each month and hour of the peak day based on SOD profiles and rules. The accredited supply of the Calibrated Baseline Portfolio is then compared to the 1-in-2 peak day demand profile for each month. The amount the accredited supply exceeds the 1-in-2 peak demand is the achieved capacity margin under the SOD rules. The Commission's process then uses the achieved capacity margin as a percentage of 1-in-2 peak demand to inform the choice of the planning reserve margin (PRM). The PRM is, therefore, intertwined with the rules used to accredit the supply of the Calibrated Baseline Portfolio; a different set of rules would produce a different amount of achieved capacity margin and a different choice of PRM. It is not possible to separate the definition of the PRM and the

accreditation of supply. The Commission should, therefore, reject Microsoft's recommendation to derive the PRM only from SERVM.

F. CalCCA Encourages the Development of a Methodology to Determine Monthly or Seasonal PRMs

Parties encourage the Commission to conduct more granular analysis and determine the best PRMs tailored to seasonal monthly periods,[22] support Vistra's proposal for seasonal PRMs and encourage further workshops,[23] and request an evaluation of whether a monthly or seasonal PRM framework could introduce ratepayer savings.[24] A prerequisite of adopting seasonal or monthly PRM is further development of the LOLE/PRM study process to identify how the fundamental relationship between reserves and loss of load varies from one month to another.

Underpinning the idea of a monthly or seasonal PRM is an expectation that the risk of unmet load for a specific level of planning reserves differs across the year. Depending on weather patterns, variability of demand around the 1-in-2 peak demand will differ from month-to-month, along with variability of wind and solar around the level accredited in the SOD accreditation rules. Potentially each month will therefore have a unique relationship between the risk of unmet load and the reserve margin, illustrated in Figure 2. A month with greater variability, illustrated by Month A, will potentially require more reserves than a month with less variability, illustrated by Month B, to achieve the same risk of unmet load.

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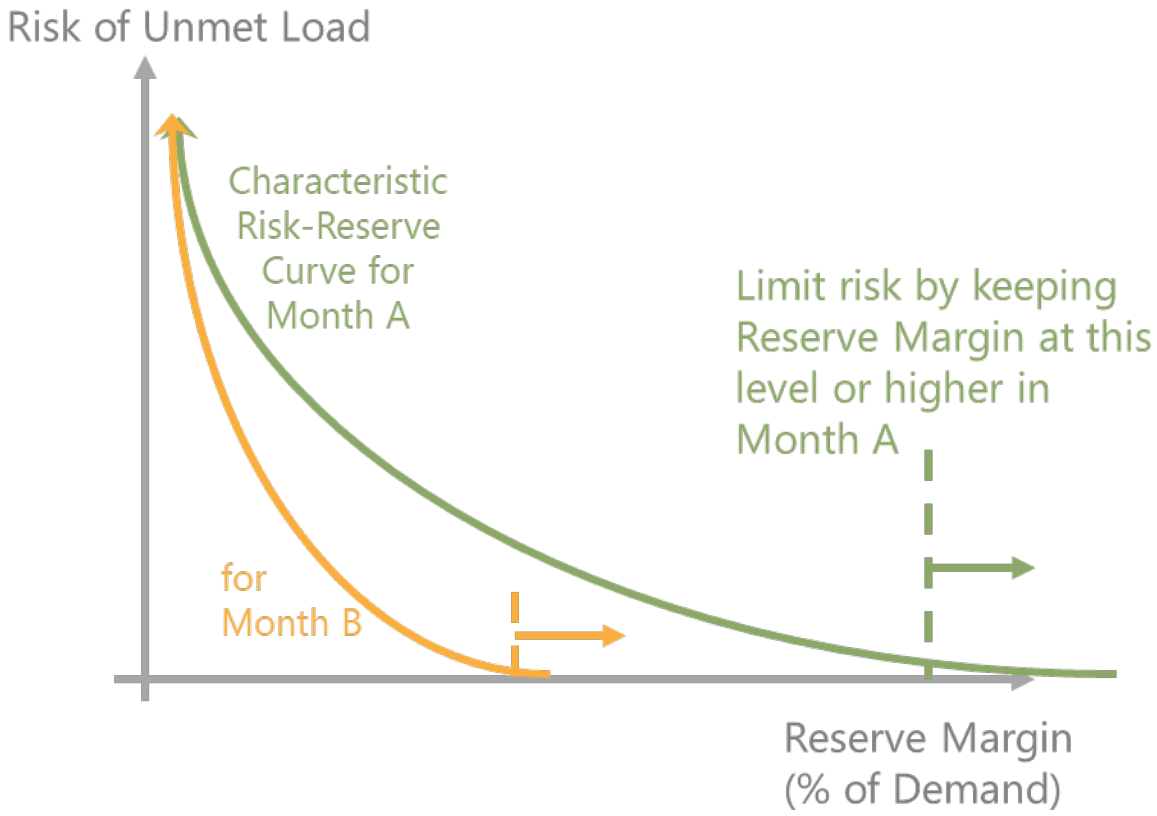
22 SCE Opening Comments at 7.
23 Microsoft Opening Comments at 5.
24 Cal Advocates Opening Comments at 4-10.

Figure 2.
Illustration of Information from SERVM Model to Identify Unique Risk-Reserve Relationships by Month



The Commissions current study process does not sufficiently characterize this risk-reserve relationship for each month. Instead, the current monthly stress test only finds the risk of unmet load for a single target reserve margin. The Commission should encourage Energy Division to expand the analysis to report the monthly LOLE across a range of reserve margins. With this information, the Energy Division and stakeholders could evaluate how various choices of reserve margins in each month or season can be used to allocate the annual 0.1 LOLE budget.

CalCCA agrees with the Cal Advocates that the justification for moving to a monthly or seasonal PRM should be based on ratepayer savings.[25] The lowest costs to ratepayers can be

[25] Cal Advocates Opening Comments at 4-10.

achieved by allocating the annual 0.1 LOLE budget to months where procuring additional reserves is the most expensive. As a result, the reserve margin in the low reserve price months may have to be set to elevated levels such that the LOLE for the low reserve price months is near zero. A simple stack analysis using the Baseline Portfolio, SOD accreditation rules, and the 1-in-2 peak day forecast for 2026 can aid in identifying the months where net supply is expected to be tightest, and RA will likely be most expensive.

III. LOCAL RA CPE REPLY COMMENTS

A. The Commission Should Reject PG&E's Proposal to Provide the Local RA CPEs with LSE Procurement Information in Advance of Its Solicitations and SCE's Modification to the Proposal

SCE supports PG&E's proposal to allow CPEs to collect information from Energy Division regarding local RA capacity already under contract with LSEs with modifications to address changes between when the CPE receives the information and the year-ahead filings.[26] CalCCA continues to recommend the Commission reject the investor owned utilities' (IOUs') proposals, including PG&E's proposal with SCE's modifications because it is unclear the intended purpose of having this information and what benefits it will provide. It is also not clear, as Cal Advocates state, "how the CPE will use the collected data to inform its solicitation and decision-making.[27] If the IOUs know that the resource is under contract to a Commission-jurisdictional LSE, the proposal seems to imply that the CPEs would then forego procuring the resource for local RA entirely.

This fundamentally alters the original CPE design that allowed any entity, including LSEs who no longer have local RA obligations, to offer to sell local RA to the CPE with equal opportunity of being procured. It may be possible to aggregate the data to prevent revealing

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[26] SCE Opening Comments at 12.

[27] Cal Advocates Opening Comments at 13.

information about *individual* LSE portfolios. However, providing the CPE with information about the local resources already under contract at an aggregate level provides the CPE with information that it may use to avoid procurement of local resources offered in its solicitations by LSEs or self-shown for compensation. This would effectively allow CPEs to take the value of local resources for free.

This also assumes the LSE that has it under contract will use it on its RA plan even though it may or may not. It could sell the resource to another LSE or out-of-state entity or hold the resource for substitution. The Commission should not adopt the IOUs' proposal to modify the voluntary self-showing process, as doing so would likely take away LSEs' opportunities to self-show the resource for compensation or sell it without providing useful information to the CPE.

B. The Commission Should Dismiss Parties' Misguided Concerns about the CalCCA CPE Timeline Proposal

While parties recognize the timing constraints put on LSEs waiting for CPE allocations,[28] and the challenge these timing constraints present for LSE procurement planning,[29] they recommend that the Commission reject CalCCA's proposal to modify the CPE timeline. These parties cite concerns that CalCCA's proposal will disincentivize self-showing, result in CPE overprocurement, or not achieve CalCCA's desired objective of providing LSEs with more certainty of the amounts of CPE allocations they will receive. For the reasons described below, these parties' concerns with CalCCA's proposal are misguided, and the Commission should reject them.

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[28] SCE Opening Comments at 10.

[29] Cal Advocates at 15.

SCE suggests:

> ... CalCCA's proposal will not accomplish the intended objective because it will discourage LSEs from timely self-showing resources... As a result of a lack of self-shown resources, the CPE may procure compensated resources to meet its compliance targets, effectively over-procuring to meet the perceived compliance need because the self-shown resources that are available in the prompt + 1 will likely not materialize in the CPE's portfolio until the next year's solicitation. The costs of over procurement are then allocated to all LSEs through the CAM, resulting in the CPE procuring above its compliance targets and providing that system RA to LSEs rather than LSEs procuring their own system RA.[30]

CalCCA's proposal[31] simply moves the timing back to that originally established for the CPE.[32] There is no reason an LSE that has procured a local resource multiple years forward would not be willing to self-show a local area resource. In fact, the CPE report issued by the Energy Division shows that in the first solicitation, the majority of local resources for the LA Basin and Big Creek Ventura area came from self-shown resources as depicted in Table 3[33] from that report.

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[30] SCE Opening Comments at 10-11.

[31] *California Community Choice Association's Proposals on Assigned Commissioner's Scoping Memo and Ruling Track 2 Central Procurement Entity Framework and IRP Coordination*, R.23-10-011 (June 14, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K837/533837255.PDF.

[32] D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program* (June 12, 2020), at 69-70.

[33] Report on the 2021-2023 Central Procurement Entity Framework May 31, 2024, at 19: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/useful-resources/final-report-on-the-2021-2023-cpe-framework.pdf.

Table 3. 2021 SCE-CPE RFO Results

2021 SCE-CPE RFO Results for LA Basin (LAB) and Big Creek/Ventura (BCV) LCAs					
Seller	**Contract Type**	**Resource Types**	**LCA**	**No. of Contracts**	**Period and Contracted Capacity (MW)**
SCE	Self-Show No-Compensation	Limited Energy Storage Resource, Combined Cycle Natural Gas, Steam Natural Gas Wind, Solar PV Hydro	LAB	55	2023, 2024: 1,117 MW–2,362 MW
			BCV		2023, 2024: 330 MW – 660 MW
Clean Power Alliance of Southern California (CPASC)	Self-Show No-Compensation	Combined Cycle Natural Gas, Solar PV	LAB	5	2023, 2024: 24 MW – 248 MW
			BCV		2023, 2024: 50 MW – 202 MW
Desert Community Energy (DCE)	Self-Show No-Compensation	Combined Cycle Natural Gas, Solar PV, Wind	LAB	3	2023-2024: 2 MW – 24 MW
	Self-Show LCR RCM			1	1 MW – 4 MW
Walnut Creek Energy LLC	RA Only	Combustion Turbine Natural Gas	LAB	1	Jun. 1, 2023 – Dec. 31, 2026: 483 MW

Given the significant volumes of self-shown resources for 2023 and 2024 in a 2021 solicitation, SCEs claim that changing to timeline back to what it was upon implementation of the CPE lacks credibility.

Cal Advocates suggests that CalCCA will not achieve its required objectives because:

> "CalCCA's proposal would require the CPEs to procure to meet targets two years before the compliance year. The two-year gap creates risks that CPE procurement may not account for variables that affect year-over-year CPE procurement targets... CalCCA's proposal still allows the CPE to perform incremental procurement to make up for changes to the local RA need since its last annual solicitation. CalCCA states that the change in local RA need year over year is "typically small" and should have minimal impact on adjustments to CPE Credits. Cal Advocates disagrees."[34]

[34] Cal Advocates Opening Comments at 16, footnotes omitted.

Cal Advocates then compares changes between the two-year ahead (Y+2) local capacity requirement (LCR) estimates against the year-ahead (Y+1) LCRs for the same compliance year. Cal Advocates states first that "Negative values indicate that the CPE would have over-procured in its solicitation two years before the compliance year."[35] First, the potential for the CPE to procure more in Y+2 than the ultimate LCR in Y+1 due to downward changes in LCRs is not a function of CalCCA's proposal to shift the timeline. Under the existing local RA CPE timeline, LCRs can decrease from Y+2 and Y+1 and if the CPE procures 100 percent of its Y+2 LCR, as required, then the CPE would still be overprocured after the LCR reduction in this scenario.

Second, while SCE and Cal Advocates express concern about overprocurement associated with CalCCA's proposal, it is the failure to resolve the timing issues that will actually risk overprocurement. If CPE allocations are allocated well enough in advance, LSEs have time to adjust their procurement plans to take into account these allocations, including selling off excess RA if their CPE allocations make them long. If, instead, LSEs overprocure because they cannot predict their CPE allocations, they will not be made aware that they overprocured until it is too late to adjust their procurement.

Cal Advocates then states that "For the PG&E CPE, CalCCA's proposal would have resulted in between 538 megawatts (MW) and 1,429 MW of incremental procurement in the last three years had the proposal been implemented" and that "[s]uch a substantial increase in CPE Credits undermines CalCCA's stated goal to mitigate CPE Credit allocation uncertainty."[36] The Commission should not view this as a substantial increase. PG&E's 2023 local RA requirement was 11,543 MW, the incremental change between Y+2 and Y+1 (1,429 MW) is only 12 percent. This should not be considered "substantial" relative to the largest PG&E Y+2 shortfall of almost

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[35] Cal Advocates Opening Comments at 16.

[36] *Id.* at 17.

40 percent of the requirement. In addition, Cal Advocates misses the point that regardless of the timing of the CPE, any change that increases the LCR must be procured or it will risk reliability in the local area. The CPE procuring for the incremental change *and* its Y+2 deficiency is a much more substantial change and creates much more uncertainty than providing the LSE its allocations after Y+2 and only updating those allocations for any procurement completed for the 1,429 MW change.

Cal Advocates suggests instead that LSEs can estimate their allocations by looking at the Y+2 procurement volumes on the CPUC website and applying their load ratio shares.[37] This is not true when the CPEs come up significantly short in Y+2, which has happened in 2023 and 2024 in the PG&E CPE territory, followed by the additional CPE procurement for any incremental changes in Y+2 and Y+1 requirements *plus* Y+2 deficiencies in Y+1. Again, if LSEs estimated their allocations based upon the results of CPE procurement in Y+2 and then the CPE resolves its entire deficiency from Y+2 in Y+1, then the LSE would have significantly overestimated its procurement obligations and overprocured. For these reasons, the Commission should reject party recommendations to reject the CalCCA local RA CPE timeline proposal.

C. CalCCA Agrees with Parties that the Long-Term Local Area Resource Transition is Best Addressed in the IRP Proceeding

CalCCA agrees with CESA that repurposing the CPE's focus to procure gas plants and new clean resources in local areas to address future retirements "change[s] the overall purpose of the local RA program from ensuring sufficient local RA will be operationally available to CAISO (via RA Plan and Supply Plan compliance) to a long-term planning and procurement exercise. Managing the long-term local area resource transition is best addressed in the IRP process."[38]

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[37] Cal Advocates Opening Comments at 18.
[38] CESA Opening Comments at 9.

A coordinated view of the resources and transmission available to replace gas or reduce local constraints is key to reducing reliance on gas resources in local areas. If the Commission addressed the transition from reliance on gas resources in local areas in the RA proceeding through repurposing the CPE, the key linkage between resource planning and transmission planning would be missing. The IRP proceeding already links to the CAISO's Transmission Planning Process. Failure to consider transmission solutions when addressing local area reliability presupposes the most cost-effective solution to minimizing reliance on local gas resources. It also presupposes that expanding the local RA CPE function to procure new local resources is superior to LSE procurement of new local resources. The Commission should, therefore, develop a methodology for planning for reduced reliance on local gas resources in the Reliable and Clean Power Procurement Program (RCPPP) in coordination with the TPP, rather than repurposing the CPE.

Parties who recommend eliminating the five-year limit on CPE procurement times or encouraging the CPE to contact for longer terms do so on the grounds of supporting new resource development[39] or facilitating procurement of local resources needed for local reliability during the energy transition.[40] These recommendations again presuppose the outcome of the RCPPP, where the Commission is considering a process for new resource development, including new resource development in local areas and the retention of existing resources necessary to support reliability during the energy transition. Given the interactions between the IRP, TPP, and local area needs, the Commission should refrain from adopting policies here that expand the use of the local RA CPE without evaluating if it makes sense for the local RA CPE to play a role within the context of these broader processes.

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[39] New Leaf Energy, Inc. Opening Comments at 2.

[40] Calpine Opening Comments at 6.

D. AReM Should Clarify How the CAISO Would Allocate Local CPM Costs

AReM's opening comments clarify that its Track 2 proposal to eliminate the CPE framework "does not propose elimination of CAISO local requirements studies. Those studies should continue and if CAISO finds that system RA procurement is inadequate for meeting local requirements, as discussed above, the CPM or CAM should be used on a case-by-case basis to remedy any shortfall."[41] While this clarification is helpful, it leaves open the question of how local CPM costs are allocated if the CAISO has to use its CPM authority to fill a local need. The CAISO's tariff requires it to first allocate costs to individually deficient LSEs, then collectively to all LSEs serving load in the local areas' TAC area by gross load share.[42] Because no individual LSE would have a local RA requirement, it appears that under AReM's proposal, costs would be allocated collectively. While this may be satisfactory, the record needs to be informed by specific information on how such cost allocation would occur and if the CAISO tariff would require any changes.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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

August 23, 2024

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41 AReM Opening Comments at 3.
42 CAISO Tariff Section 43A.8.3.

APPENDIX
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING TRACK 2 SCHEDULE

LOAD PROFILE ANALYSIS

Energy Division's analysis indicates that the 2022 weather year makes the greatest contribution to LOLE of all 23 weather years. The highest consumption and managed load for the CAISO region of the 23-year dataset occurs on a single day with the 2022 September weather year.[43] CalCCA finds that the Energy Division's managed load shape for the peak September 2022 weather year is shifted later in the day compared to the observed CAISO peak managed load,[44] inclusive of estimated demand response,[45] on September 6, 2022. CalCCA adjusted the Energy Division managed load data to remove the BTM PV growth expected between 2022 and 2026 (about 47 percent more BTMPV in 2026) and to remove the weather-normalized load growth expected between 2022 and 2026 (about seven percent higher consumption in 2026). Even with this adjustment of the Energy Division managed load shape back to 2022 levels, the Energy Division load shape (red line) appears to peak two hours later in the day than the observed CAISO peak (black line). CalCCA extended the same comparison to the August 18, 2020 peak day[46] and found a similar mismatch in the Energy Division load shapes.

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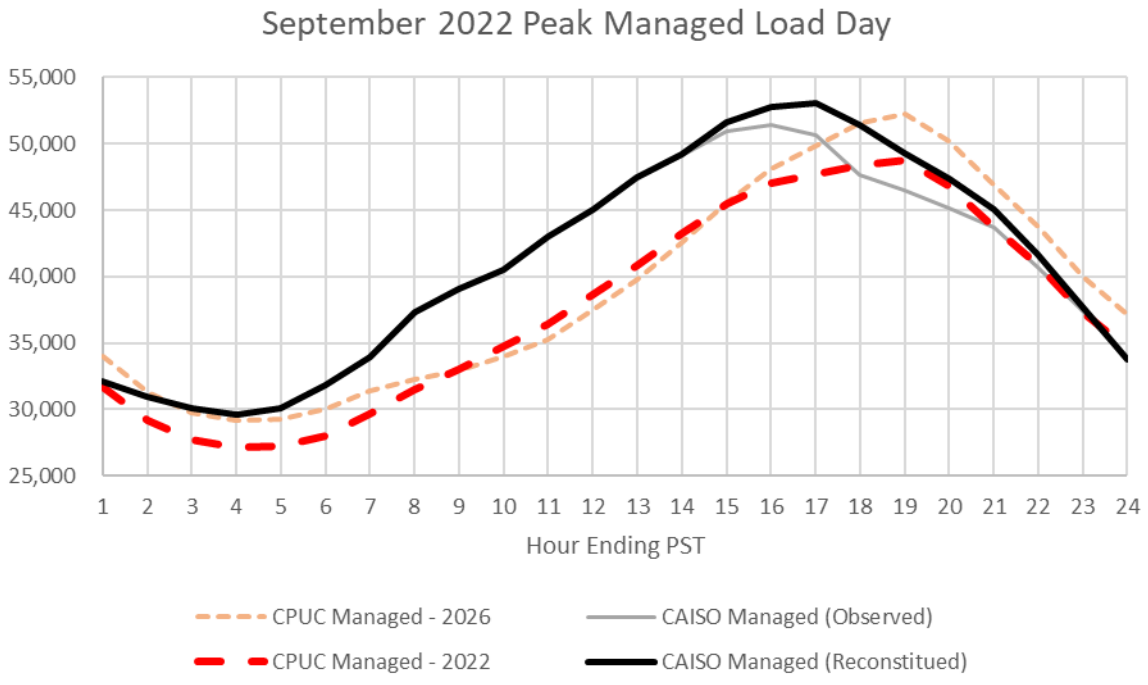
[43] CalCCA analysis of the Energy Division hourly load data for 2026, at https://files.cpuc.ca.gov/energy/modeling/2024_servm_updates/HourlyLoadComponents_CAISO_2026.csv.

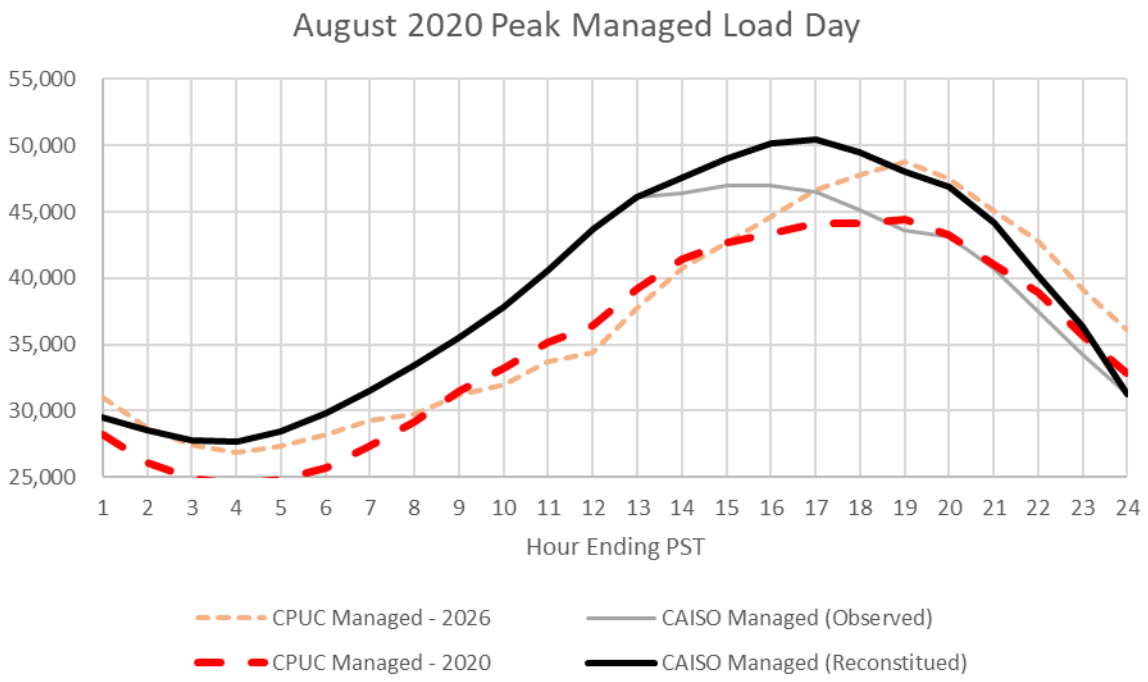
[44] CAISO 2022 Production and Curtailments Data: https://www.caiso.com/documents/productionandcurtailmentsdata_2022.xlsx.

[45] September 6, 2022 demand response estimated from Figure 22 of CAISO's *Summer Market Performance Report for September 2022*. https://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf.

[46] CAISO load data from https://www.caiso.com/documents/productionandcurtailmentsdata_2020.xlsx and demand response data from Figure 3.7 of https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

Figure 1. Comparison of CAISO managed load during September 2022 and August 2020 peak events and the Energy Division's Managed Load profiles with 2022 and 2020 weather data





California Community Choice Association

SUBMITTED 08/26/2024, 02:41 PM

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

1. Please provide a summary of your organization's general comments on the meeting regarding alternative proposals.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the August 19, 2024, stakeholder call. The CAISO presented a revised schedule, alternative proposals put forth by the California Energy Storage Alliance (CESA) and Vistra Corp. (Vistra), and an analysis of the frequency of storage mitigation to inform potential instances of warranted Bid-Cost Recovery (BCR).

The concerns that the CAISO listed, lack of exposure to real-time (RT) prices and incentives to bid strategically, are legitimate issues that the stakeholder process should address. The CAISO will need to determine how much of each objective can be addressed immediately and which may take a longer-term initiative to address. In summary:

- CalCCA thanks the CAISO for extending the schedule of this initiative to allow more time to have a robust discussion of solutions that specifically target unwarranted BCR payments.
- The CESA proposal and Vistra proposals warrant additional discussion and consideration. The CAISO should explore the open questions associated with these alternative proposals to allow stakeholders to assess their merits fully.
- CalCCA appreciates the CAISO's presentation of instances of mitigation, including cases in which BCR payments to storage resources would likely be warranted.

The CAISO's revised schedule, presentation of alternative solutions, and presentations of cases where BCR may be warranted will allow for a more robust discussion of the potential of solutions that effectively address unwarranted BCR payments while providing fair compensation for storage resources.

2. Please provide your organization's comments regarding the updated schedule of the initiative.

CalCCA appreciates the CAISO's revised schedule of the initiative, which will provide more time for stakeholders to evaluate and comment on the CAISO's proposal and stakeholder-proposed alternatives. It will also allow more time to consider which instances warrant BCR, like when resources are mitigated, and the magnitude of those instances. The revised schedule will allow more time to have a robust discussion of solutions that specifically target unwarranted BCR payments. The CAISO should consider whether one of its concerns will be easier to address within the updated schedule than the other. In addition, if one of the two concerns is more difficult to address, the CAISO should evaluate whether it is feasible to put forth proposals that address both within the updated schedule or if an additional phase of the stakeholder process will be necessary.

3. Please provide your organization's comments regarding the alternative proposals put forth by stakeholders, the outstanding questions regarding their implementation, and how they compare relative to the status quo and the Proposed Solution.

Within the stakeholder initiative, the CAISO should include further examples and description of how BCR is triggered. This information will help stakeholders to better understand the changes being contemplated.

Unwarranted BCR payments can result from the current framework's disincentives to consider RT market conditions due to limited RT price exposure that could incentivize resources to bid inefficiently to maximize BCR payments. The CAISO and the Department of Market Monitoring have identified an increase in BCR payments

to storage resources related to the buy-back or sell-back of day-ahead schedules due to state-of-charge constraints. This can create market inefficiencies and increased costs that could be exacerbated by the ability of storage to bid above the soft-offer cap. However, BCR payments are warranted if the buy-back or sell-back results from the CAISO's market design preventing resources from reflecting RT conditions in the RT energy bids and, therefore, dispatching storage in a way that makes them eligible for BCR. In these cases, BCR is warranted, and the CAISO should aim to develop a solution that differentiates between unwarranted and warranted BCR.

CESA and Vistra proposed alternative solutions to the CAISO's straw proposal. CESA's proposal would modify the RT BCR calculation to replace the resource's RT bid price with the day-ahead energy price. This proposal intends to allow storage resources to continue existing bidding practices without inadvertently increasing BCR payments or offering strategic RT bids to increase revenues through BCR payments. Vistra makes a similar proposal to CESA but would use the resources' default energy bid rather than the day-ahead energy price in the BCR calculation. It also advances a proposal to exclude resources from BCR in the intervals where the scheduling coordinator has submitted an outage card or bid parameters that derate or rerate the resource. While CalCCA does not take a position on its preferred approach at this time, the CESA and Vistra proposals warrant further consideration, as they could offer improvements to the CAISO's proposed blunt mechanism for excluding storage resources from BCR. The CAISO should continue to explore the open questions it identified associated with these proposals so that stakeholders can assess the merits of these proposed alternatives.

4. Please provide any other proposals your organization considers the ISO should assess. Please include as much detail as possible.

CalCCA has no alternative proposals at this time.

5. Please provide your organization's comments regarding the issues regarding mitigation as well as the initial analyses presented by the ISO.

Stakeholders and the Market Surveillance Committee have noted that if storage is mitigated prior to the buy-back or sell-back, they may warrant BCR payments. This is one case beyond the resource operator's control that can prevent a resource from having sufficient state of charge to follow its day-ahead schedule and prevent it from recovering its costs fully through market participation. The CAISO's presentation indicates that about 41 percent of BCR payments to storage were paid to mitigated resources. This number is not insignificant and signals that the ultimate solution must consider instances where BCR is warranted.

6. Please provide any additional comments, feedback, or examples regarding the stakeholder meeting. You may upload examples or data using the "Attachments" field below.

CalCCA has no additional comments at this time.

August 26, 2024

California Public Utilities Commission – Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Via email to EDTariffUnit@cpuc.ca.gov

Re: Joint Community Choice Aggregators' Response to the Self-Generation Incentive Program (SGIP) Program Administrators' Advice Letter Proposing Revisions to the SGIP Handbook (Southern California Edison Company's Advice Letter 5347-E *et al.*)

To the Energy Division's Tariff Unit:

Pursuant to Rule 7.4.1 of the California Public Utilities Commission's (Commission) General Order 96-B,[1] Ava Community Energy, Clean Power Alliance of Southern California (Clean Power Alliance), Marin Clean Energy, Peninsula Clean Energy, San Diego Community Power, San José Clean Energy, and Sonoma Clean Power Authority (collectively the "Joint CCAs") submit this Response to the Self-Generation Incentive Program (SGIP) Program Administrators' (PA) Tier 2 Advice Letter[2] proposing revisions to the SGIP Handbook pursuant to Ordering Paragraph (OP) 23 of Decision (D.) 24-03-071, submitted on August 5, 2024 (Advice Letter or AL).

The Commission's General Rules allow a party to submit a response for the purposes of providing useful information related to the advice letter, as opposed to a protest, which objects in whole or in part to the relief requested in the advice letter.[3] The Joint CCAs provide this response in order to provide the Commission information—and seek clarification—regarding: (1) the requirement that customers installing an energy storage project participate in a qualified demand response (DR) program, and (2) the requirement that customers participating in the Residential Solar and Storage Equity (RSSE) and Equity Resiliency Budgets demonstrate income verification in their Reservation Request Form (RRF) for the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance Program (FERA).

With respect to the qualified DR program participation requirement, the current requirements in the SGIP Handbook risks forcing residential unbundled customers—roughly 50 percent of customers statewide—to forego SGIP storage budget incentives or opt out of community choice aggregator (CCA) service in order to receive those incentives. With respect to the CARE/FERA proof of income verification requirement, the SGIP Handbook risks creating new, unnecessary barriers to participation among customers that have historically had limited

[1] General Order No. 96-B, General Rules sec. 7.4.1 (GO 96-B).

[2] Southern California Edison Company Advice Letter (AL) 5347-E, Center for Sustainable Energy AL157-E, Southern California Gas Company AL 6350-G, and Pacific Gas and Electric Company AL 4952-G/7345-E (AL 5347-E et al).

[3] GO 96-B, General Rules sec. 7.4.1.

access to SGIP funding, undermining the goals of the Commission's Environmental and Social Justice Action Plan.[4] As further described below, the Joint CCAs therefore request the Commission issue a disposition letter or otherwise clarify that:

- The SGIP PAs are permitted to exempt CCA customers from the DR program participation requirement to the extent a qualified DR program is not available to that customer;
- The DR programs currently included in Appendix E to D.24-03-071 are not available or accessible to residential CCA customers;
- SGIP PAs must categorically exempt residential CCA customers from the DR program participation requirements until either: (1) the residential CCA customer is eligible to participate and may self-enroll in a CCA DR program that is included on the SGIP Qualified DR Program List; or (2) the residential CCA customer has access to an investor-owned utility (IOU) DR Program on the SGIP Qualified DR Program List at the time the RRF is submitted;
- CCAs are permitted to file Tier 2 advice letters adding CCA programs to the list of qualified DR programs for SGIP purposes;
- CCAs seeking to add their programs to the list of qualified DR programs for SGIP purposes must demonstrate the same requirements as established for POU customers,[5] and;
- Enrollment in CARE or FERA rates can be demonstrated with the submission of the customer's utility bill.

I. Qualified DR Program Participation Requirement

A. The SGIP List of Qualified DR Programs Are Not Available or Accessible to Residential CCA Customers.

D.24-03-071 requires that new customers in any storage budget category seeking SGIP incentives enroll in one of eight "qualified DR programs" listed in Appendix E to that decision ("SGIP List of Qualified DR Programs").[6] To date, that list includes only IOU-administered critical peak pricing (CPP) programs and capacity bidding programs (CBP).[7] Those programs are not available or accessible to residential CCA customers.

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[4] CPUC, ESJ Action Plan (Vol. 2), April 2022, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf, p. 23. ("GOAL 2: INCREASE INVESTMENT IN CLEAN ENERGY RESOURCES TO BENEFIT ESJ COMMUNITIES, ESPECIALLY TO IMPROVE LOCAL AIR QUALITY AND PUBLIC HEALTH").

[5] D.24-03-071 at 76 (paragraph 7).

[6] *Id.*, at 75.

[7] *Id.*, Appendix E.

CPP programs are available only to bundled customers.[8] And while the IOUs' CBP programs are nominally open to both residential and non-residential customers, PG&E, SCE and SDG&E market their programs **only** to non-residential customers, which means that no residential aggregators currently participate in the IOUs' CBPs.[9] Further, under program rules, the Joint CCAs' understanding is that an individual residential customer could not personally enroll in the IOUs' CBPs.[10] Thus, as a practical matter, CBPs are not available to residential CCA customers because residential customers currently have no pathway to enroll in those programs.

The Joint CCAs acknowledge that D.24-03-071 allows CCAs to develop their own qualified DR programs. Indeed, CCAs continue to develop and offer a diverse range of DR programs, and certain CCAs have developed or are developing DR programs that meet the "qualified DR program" criteria established in D.24-03-071. To the extent a CCA DR program is added to the SGIP list of qualified DR programs,[11] residential customers <u>of that CCA</u> would be able to access a qualified DR program.

With that said, the fact that CCA programs *may be added* to the list of qualified DR programs in the future is not a practical, near-term solution for the vast majority of residential CCA customers seeking (and otherwise eligible for) SGIP incentives. It is not reasonable to expect a CCA to develop an entire new DR program simply to allow its customers to access SGIP funds. Critically, launching a new program takes time and resources in addition to often requiring complementary regulatory processes. CCAs that have not already made significant progress in developing "qualified DR programs" are unlikely to develop and launch a program in time for their customers to access SGIP funds.[12]

In sum, the programs included in the SGIP List of Qualified DR Programs are not available to residential CCA customers. Unless those customers are promptly and efficiently exempted from the qualified DR program participation requirement (as discussed below), those customers will be required to either forego SGIP incentives or opt out of CCA service in order to receive SGIP incentives— at least one CCA has already received inquiries from customers considering opting

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[8] PG&E's CPP programs include the SmartRate for residential customers and Peak Day Pricing (PDP) for non-residential customers. *See* PG&E SmartRate tariff, available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-RSMART.pdf; *See* PG&E "Peak Day Pricing", available at: https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/peak-day-pricing.html.; SCE Schedule CPP (Critical Peak Pricing).

[9] The Joint CCAs acknowledge that third parties could, in theory, aggregate residential CCA customers to participate in the relevant IOU's CBP. That option, however, does not make the CBP "available" to residential CCA customers, because it is predicated on (currently non-existent) market interest. CCAs cannot require third parties to aggregate their residential customers for CBP purposes.

[10] *See, e.g.,* PG&E Electric Schedule E-CBP (Capacity Bidding Program); SCE Schedule CBP (Capacity Bidding Program); SDG&E Schedule CBP (Capacity Bidding Program).

[11] The Joint CCAs discuss their concerns related to the process for adding CCA DR programs to the qualified DR program list in Section I.C. of this Response.

[12] The proof of participation in a SGIP Qualified DR program occurs with the submission of the Incentive Claim Form (ICF) which, for residential customers, usually occurs within 6-12 months of the initial incentive reservation.

out of CCA service and returning to PG&E's bundled service in order to enroll in SGIP qualifying DR programs.[13] That would be an inequitable, anti-competitive, unreasonable and unfair outcome the Commission could not have intended, given that CCA customers pay for SGIP through public purpose program (PPP) rates and must therefore have access to the program's benefits. To contextualize the scale of this problem, roughly 50 percent of the customers of the three large IOUs are CCA customers and likely even a larger portion of SGIP applicants will be CCA customers. As such, a majority of SGIP applicants could be forced to choose between foregoing SGIP incentives and opting out of CCA service. In order to avoid this outcome, the Commission should establish a process that allows CCA residential customers to be efficiently exempted from the qualified DR program participation requirement (until and unless a qualified DR program is available to those customers). The Joint CCAs describe such a process, below.

B. In Order To Avoid Forcing Customers to Depart CCA Service Just To Receive SGIP Incentives, CCA Residential Customers Must Be Efficiently Exempted From the Qualified DR Program Requirement.

D.24-03-071 permits PAs, in consultation with the SGIP working group, to exempt an applicant from the DR participation requirement if:

1. A non-IOU customer does not have access to qualified DR programs; or
2. A customer would have to forfeit a low-income rate to join a DR program.[14]

As the Joint CCAs explain above, residential CCA customers must be efficiently exempted from the qualified DR program participation requirement in order to avoid inadvertently forcing those customers to either forego SGIP incentives or opt-out of CCA service.

The Joint CCAs make two recommendations to facilitate streamlined exemptions. First, the Commission should clarify that per D.24-03-071, the SGIP PAs are permitted to exempt CCA customers from the DR program participation requirement to the extent a qualified DR program is not available to that customer. The Commission should further clarify that the DR programs currently included in the SGIP List of Qualified DR Programs are not available or accessible to residential CCA customers.

Second, the Commission should establish a straightforward, streamlined exemption process to ensure all customers without access to a qualified DR program are able to receive SGIP incentives without delay. Unfortunately, the exemption process currently prescribed by the SGIP Handbook is unworkable. That process requires SGIP Working Group (WG) approval for each individual customer exemption.[15] This is an impractical requirement given that roughly 50 percent of SGIP applicants may require exemptions and that the reason for the exemption is the same across all customers.

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[13] Marin Clean Energy has received inquiries from customers considering opting out of CCA service and returning to PG&E's bundled service in order to enroll in SGIP qualifying DR programs.

[14] D.24-03-071 at 76.

[15] SGIP Handbook at Section 6.2.4.

The Joint CCAs recommend that SGIP PAs categorically exempt residential CCA customers from the DR program participation requirements until either:

1. The residential CCA customer is eligible to participate and may self-enroll in a *CCA DR program* that is included on the SGIP Qualified DR Program List; or
2. The residential CCA customer has access to an *IOU DR Program readily available for enrollment* at the time the RRF is submitted.

To provide customers certainty about their SGIP incentive at the time of the initial incentive reservation, it is not enough to "promise" residential customers access to an SGIP Qualified DR Program at the ICF stage if no enrollment options are available at the RRF stage. Rather, SGIP PAs should add a checkbox to the RRF and ICF forms that allows the customer to request the exemption, along with an attestation that no qualified DR program is available to the customer.

C. The Process for Adding CCA Programs to the Qualified DR Program List Must Be Simplified and Clarified.

D.24-03-071 directs SGIP PAs to add to the SGIP List of Qualified DR Programs "any qualified DR programs that may be offered to statewide customers by other non-IOU electric providers."[16] Based on that direction, the Joint CCAs understand that over time, the list of qualified DR programs can and must grow to include CCA programs meeting the criteria in D.24-03-071.

The *process* for updating the SGIP List of Qualified DR Programs, however, requires clarification. The Decision does not expressly permit CCAs to file advice letters adding their own programs to the list of qualified DR programs (unlike D.23-12-005, which expressly permits CCAs to submit a Tier 2 Advice Letter identifying DR programs meeting the criteria for a qualified DR program established in that decision).[17]

CCAs recommend the Commission clarify that CCAs are permitted to file their own advice letters adding CCA programs to the SGIP List of Qualified DR Programs, such that IOUs are not placed in the position of being the "gatekeepers" for that list. Further, the Commission should direct SGIP PAs to update the SGIP List of Qualified DR Programs on the SGIP website within five business days of Commission approval of a CCA's AL.

Finally, to remove any ambiguity regarding the showing a CCA must make in order for a CCA DR program to be added to the SGIP List of Qualified DR Programs, the Joint CCAs recommend the Commission clarify that CCAs seeking to add their programs to the list must demonstrate the same requirements as established for POU customers, which are as follows:

1. The storage device shifts onsite energy use to off-peak time periods of reduce demand from the grid by offsetting or lowering some or all of the customer's onsite energy demand;
2. The DR program is not a Reliability Demand Response Resource (RDRR) that is use-limited; and

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[16] D.24-03-071 at 75-76.

[17] D.23-12-005 at 25.

3. The load impact from the storage device can be accurately measured and evaluated.[18]

II. Required Documentation to Confirm CARE/FERA Enrollment.

Residential single-family customers participating in the RSSE or Equity Resiliency Budgets can demonstrate income eligibility by either:

1. Providing documentation showing the Host Customer's household income is 80% of the area median income or less; or
2. Showing proof of enrollment in the MASH, SOMAH, SASH, DAC-SASH, CARE, FERA or ESA Programs.

If showing income eligibility via enrollment in the CARE, FERA and ESA programs, a participating customer must also prove with the RRF submission that "income verification has been completed as a result of participation in the programs."[19]

The Joint CCAs recommend the IOU, rather than the customer, confirm the customer's enrollment in CARE or FERA. Host customers are already required to submit a utility bill with the RRF submission, and that bill specifically states whether the customer is enrolled in CARE/FERA. As such, host customers should not be required to submit any further documentation to confirm CARE/FERA enrollment. Requiring customers or their SGIP Applicants to provide documentation demonstrating that income verification has been completed as a result of a customer's enrollment in CARE/FERA is not only impractical (it is unclear what documentation a customer could submit to fulfill this requirement), but also an inequitable and inappropriate burden for a set of customers who have historically had limited access to SGIP incentives.[20] The CARE and FERA programs have successfully used self-attestation in the past to avoid the unintentional exclusion of qualifying customers. The Commission should take care not to impose a new burden on CARE/FERA customers should those customers seek SGIP incentives. Instead, CARE/FERA enrollment should simply be proven via the host customer's utility bill, a document that is already being submitted to the SGIP PA with the RRF submission.

With that said, to the extent the Commission does not waive the requirement that the customer must demonstrate that income verification for CARE/FERA has been completed, the SGIP PAs must more specifically describe the documentation they require.

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[18] D.24-03-071 at 76 (see paragraph 7).

[19] AL 5347-E et al. at 87.

[20] *See,* Comments of California Senate Bill 350 Disadvantaged Communities Advisory Group on Rulemaking 20-05-012 Assigned Commissioner's Ruling on Improving Self Generation Incentive Program Equity Outcomes and Assembly Bill 209 Implementation at 2 (Dec. 2, 2022) (recommending enabling customers who qualify for CARE/FERA to participate in SGIP without additional paperwork), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K629/499629300.PDF.

III. Conclusion

D.24-03-071 establishes a qualified DR program participation requirement for customers receiving SGIP incentives, but leaves critical gaps in the process for granting exemptions to CCA customers who do not have access to qualified DR programs. Additionally, D.24-03-071 does not present a clear pathway for CCAs to directly add their programs to the list of qualified DR programs as and when they are developed. The SGIP Handbook revisions proposed in AL 5347-E et al. do not fill those gaps. Further, the SGIP Handbook's requirements related to the demonstration of CARE/FERA enrollment would unnecessarily burden low-income customers. The Joint CCAs therefore request the Commission issue a disposition letter or otherwise clarify that:

- The SGIP PAs are permitted to exempt CCA customers from the DR program participation requirement to the extent a qualified DR program is not available to that customer;
- The DR programs currently included in Appendix E to D.24-03-071 are not available or accessible to residential CCA customers;
- SGIP PAs must categorically exempt residential CCA customers from the DR program participation requirements until either: (1) the residential CCA customer is eligible to participate and may self-enroll in a CCA DR program that is included on the SGIP Qualified DR Program List; or (2) the residential CCA customer has access to an IOU DR Program on the SGIP Qualified DR Program List at the time the RRF is submitted;
- CCAs are permitted to file Tier 2 advice letters adding CCA programs to the list of qualified DR programs for SGIP purposes;
- CCAs seeking to add their programs to the list of qualified DR programs for SGIP purposes must demonstrate the same requirements as established for POU customers,[21] and;
- Enrollment in CARE or FERA rates can be demonstrated with the submission of the customer's utility bill.

The Joint CCAs appreciate Energy Division's consideration of these comments.

[21] D.24-03-071 at 76 (paragraph 7)

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association recommends adoption of the Proposed Decision, with the following modifications:

- The California Public Utilities Commission (Commission) should specify that the proportional allocation method is to be applied to all past due payments, including partial payments; and
- The Commission should require the investor-owned utilities to modify their tariffs to apply the proportional allocation method for all past due payments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Extending Current Proportional Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*[3] (Proposed Decision), dated August 8, 2024. The Proposed Decision directs Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUS) to continue to allocate all payments,

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[3] Proposed *Decision Extending Current Proportional Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*, Rulemaking (R.) 18-07-005 (Aug. 8, 2024): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=537555377.

including partial payments, made on past-due electric utility bills between the IOUs and community choice aggregators (CCA), based on their proportionate share of those past-due bills unless and until the Commission orders otherwise.

I. INTRODUCTION

CalCCA supports the Proposed Decision's indefinite extension of the proportional allocation method for all past due payments, including partial payments. The Proposed Decision prohibits the IOUs from utilizing the "waterfall" method, which is the IOU standard practice of crediting customer partial payments on delinquent unbundled customer accounts first to the IOU portion of the bill until the customer account is no longer subject to disconnection for delinquency, and only then to the CCA bill portion. As noted in CalCCA's comments and reply comments on the March 22, 2024 Ruling requesting comments on the waterfall and proportional allocation methods,[4] the waterfall method is not required by statute or Commission directive. Rather, it is embedded in the Commission-approved IOU tariffs. After the waterfall was suspended multiple times during the COVID pandemic, the Commission in Decision (D.) 21-11-014[5] extended the waterfall suspension through September, 2024. Once adopted, this Proposed Decision will continue both the suspension of the waterfall, and the requirement that the IOUs allocate partial past due payments proportionately between the IOUs and CCAs "unless and until the Commission determines otherwise."[6]

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[4] *Administrative Law Judge's Ruling on Disconnection Caps and Past-due Payment Allocation,* R.18-07-005 (Mar. 22, 2024); *see California Community Choice Association's Comments on Administrative Law Judge's Ruling on Disconnection Caps and Past-due Payment Allocation,* R.18-07-005 (Apr. 19, 2024); *see also California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling on Disconnection Caps and Past-due Payment Allocation,* R.18-07-005 (May 3, 2024).

[5] D.21-11-014, *Decision Directing Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*, R.21-02-014 (Nov. 18 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K116/424116557.PDF.

[6] Proposed Decision, Ordering Paragraph (O¶) 1, at 12.

Consistent with D.21-11-014, the Proposed Decision requires the continuation of the proportional allocation to: (1) prevent the "inappropriate[] shift [of] financial risk to the CCAs, . . . [and] contribute to the financial stability of the CCAs," because "[c]ustomers as a whole benefit from more financially stable CCAs,"[7] (2) ensure equitable treatment of both bundled and unbundled customers, (3) continue the application of D.21-11-014 as "the standard" and promote "strengthening the financial position of the CCAs [which] benefits all customers,"[8] and (4) reaffirm D.21-11-014's finding that no statute obligates or prohibits either the waterfall or proportional allocation method. CalCCA supports and recommends adoption of the Proposed Decision, with the following modifications:

- The Commission should specify that the proportional allocation method is to be applied to all past due payments, including partial payments; and
- The Commission should require the IOUs to modify their tariffs to require the proportional allocation method be used for all past due payments.

II. THE PROPOSED DECISION'S DIRECTIVES FOR THE IOUS TO CONTINUE THE PROPORTIONAL ALLOCATION METHOD SHOULD BE ADOPTED

The Proposed Decision's directives for the IOUs to continue the proportional allocation between the IOUs and CCAs of all customer payments, including partial payments, on past-due electric utility bills should be adopted. The Proposed Decision requires the use of the proportional allocation method because it:

- **Prevents Disproportionate Allocation of Financial Risk to CCAs:** The "conclusions from D.21-11-014 still hold" and "the waterfall method inappropriately shifts financial risk to the CCAs,"[9] and "[t]he proportional allocation method contributes to the financial stability of the CCAs, and financially sound CCAs benefit customers as a whole";[10]

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7 *Id.*, at 5.
8 *Id.,* at 8.
9 *Id.,* at 5.
10 *Id.*, Findings of Fact (FoF) 3, at 11.

- **Ensures Equitable Treatment of Bundled and Unbundled Customers:** Bundled and unbundled customers are treated equitably given: (1) both classes of customers are obligated to pay energy and distribution charges for reconnection of service, (2) the prevention of cost shifts from bundled to unbundled customers given the financial burden that the waterfall places on CCAs, and (3) the prevention of the uneven support provided by the waterfall to customers with the option to unbundle;[11]

- **Supports the Public Interest by Ensuring Financial Viability of CCAs:** The public interest is served because "strengthening the financial position of the CCAs benefits all customers" given that "CCAs are in the public interest, in that CCAs allow for a publicly-managed alternative to private utility procurement of resources;"[12] and

- **Furthers Legislative Intent:** Relevant Public Utilities Code sections neither obligate nor prohibit the Commission from adopting either the waterfall or proportional allocation method, and the legislature has obligated use of the proportional allocation method in certain circumstances, thereby preventing the universal availability of the waterfall method and supporting adoption of the proportional allocation method.[13]

CalCCA supports the adoption of the Proposed Decision, with the revisions set forth below.

III. THE COMMISSION SHOULD SPECIFY THE PROPORTIONAL ALLOCATION METHOD APPLIES TO ALL PAST DUE PAYMENTS, INCLUDING PARTIAL PAYMENTS

While the intent of the Proposed Decision is clearly to require the proportional allocation method for partial past due payments, the language of the Proposed Decision should be clarified to incorporate this nuance. Past due payments in full are already allocated proportionally between the IOUs and CCAs according to the IOU tariffs.[14] Therefore, the Commission should specify in the Proposed Decision that the proportional allocation method is now being extended to partial past due payments.

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[11] *Id.,* at 5-6; FoF 4, at 11.
[12] *Id.*, at 7-8.
[13] *Id.,* at 8.
[14] *See* PG&E Electric Rule 23, R.2; SCE Rule 23, R.2; and SDG&E Rule 27, R.2.

IV. THE COMMISSION SHOULD REQUIRE MODIFICATION OF THE IOUS' TARIFFS TO REQUIRE THE PROPORTIONAL ALLOCATION FOR ALL PAST DUE PAYMENTS

The Commission should require modification of the IOUs' approved tariffs which allow the waterfall method. As noted in the Proposed Decision, the waterfall method is not required by statute or Commission directive but is embedded in the Commission-approved IOU tariffs.[15] While the IOU tariffs explicitly allow the waterfall and the Proposed Decision indefinitely prohibits it, the Proposed Decision's Conclusions of Law 2 states:

> Approved tariffs of PG&E, SDG&E, and SCE prioritizing payments first to utility charges and second to non-utility charges are **not changed** by today's decision.[16]

To ensure IOU compliance with the Decision and prevent customer confusion over the allocation of their partial past-due payments, the Proposed Decision should be modified to require the IOUs' Tariffs to incorporate the proportional allocation method.

For example, PG&E's Electric Rule 23, Section R.2 requires proportional allocation for partial payments, but Section R.3 requires the waterfall for past due partial payments. An asterisk was added during the COVID pandemic that is also currently out of date:

> 2. Except as provided below in Section 3, if a customer makes only a partial payment for a service account, the payment shall be allocated proportionally between PG&E's charges and the CCA's charges. A customer may dispute these charges . . . , but shall not otherwise have the right to direct partial payments for a particular service account.
>
> 3. In evaluating a delinquent residential Service Account for service termination and to the extent required by law or Commission regulations, partial payments shall be allocated first to delinquent disconnectable charges.*
>
> *Due to the COVID-19 pandemic and pursuant to CPUC Resolutions M-4842, M-4849 and D.21-06-036, PG&E has suspended Section R.3 of Electric Rule 23 and will allocate partial payments received from residential CCA

[15] Proposed Decision, FoF 6, at 12 ("Statute neither obligates nor prohibits the Commission from adopting the proportional allocation or waterfall method").

[16] *Id.*, COL 2, at 12.

> customers on a pro rata basis with CCAs for up to one year, through September 30, 2021, as described in Advice 4244-G-A/5516-E-A, Advice 4388-G/6092-E and Advice 4475-G/6290-E.

Without revision, not only will PG&E's tariff still require the waterfall method for past due partial payments, but will also cause confusion as to the outdated reference to the use of the proportional allocation method only until September 30, 2021.

SCE's Electric Rule 23, Section R.2, also requires revision to incorporate the proportional allocation method, as it currently requires the waterfall when the customer's account is delinquent:

> 2. Partial payments by customers shall be allocated on a pro rata basis to SCE charges for which delinquency may result in disconnection, and then any balance shall be prorated between the CCA and other SCE charges.

SDG&E Electric Rule 29, Section R.2 is virtually identical to SCE's rule and also needs revision to reflect that the proportional allocation method will apply to all past due payments:

> 2. Partial payments by customers shall be allocated on a pro rata basis to the Utility charges for which delinquency may result in disconnection, and then any balance shall be prorated between the CCA and other Utility charges.

To ensure IOU compliance with the final decision and prevent customer confusion over the allocation of their partial past-due payments, the Proposed Decision should be modified to require the IOUs' Tariffs to reflect the proportional allocation method. As set forth in Appendix A attached hereto, the Commission should revise Conclusion of Law (COL) 2 as follows:

> 2. Approved tariffs of PG&E, SDG&E, and SCE prioritizing partial payments first to utility charges and second to non-utility charges ~~are not changed by~~ must be revised within 30 days to incorporate today's decision.

In addition, the Commission should add the following Ordering Paragraph:

2. Within 30 days of the Decision, PG&E, SDG&E, and SCE shall each file a Tier 1 Advice Letter revising their tariffs to require all past due utility payments, partial or otherwise, to be allocated between the CCA and utility on a proportional basis.

V. CONCLUSION

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

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 28, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

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

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **bold and underlined**

FINDINGS OF FACT

1. Electric utility tariffs allow the IOUs to apply **partial** payments on outstanding bills first to the utility charges on the bill and secondly to non-utility charges on the bill. This is known as the waterfall method.

2. D.21-11-014 of R.21-02-014, required the electric IOUs to allocate **partial** payments received on outstanding customer accounts proportionally between utility charges and CCA charges, regardless of customer disconnection status. This is known as the proportional allocation method.

CONCLUSIONS OF LAW

2. Approved tariffs of PG&E, SDG&E, and SCE prioritizing **partial** payments first to utility charges and second to non-utility **charges** ~~**are not changed by**~~ **must be revised within 30 days to incorporate** today's decision.

ORDERING PARAGRAPHS

1. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall allocate all types of payments**, including partial payments,** made on past-due electric utility bills between utilities and Community Choice

Aggregators based on their proportionate share of those past-due bills, regardless of the customer's disconnection status, unless and until the Commission determines otherwise.

New Order:

2. Within 30 days of the Decision, PG&E, SDG&E, and SCE shall each file a Tier 1 Advice Letter revising their tariffs to require all past due utility payments, partial or otherwise, to be allocated between the CCA and utility on a proportional basis.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ESTABLISHING TARGET ENERGIZATION TIME PERIODS AND PROCEDURE FOR CUSTOMERS TO REPORT ENERGIZATION DELAYS

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) recommends that the California Public Utilities Commission (Commission):

- Adopt the Proposed Decision's immediate establishment of statewide targets for Electric Rules 15, 16, 29, 45, and main panel upgrades, and the timelines for projects requiring upstream capacity upgrades;

- Adopt the Proposed Decision's approach to consequences for failure to comply with the targets/timelines in Phase 1, including finding an investor-owned utility (IOU) out of compliance if five percent or more of an IOU's energization requests are overdue in one year, and monitoring compliance to assess the adoption of additional consequences in Phase 2;

- Refine the Proposed Decision's reporting requirements to ensure increased transparency, including requiring: (1) reporting on all pending and future energization requests, (2) the identification of the load serving entity serving a site or project, (3) reporting on IOU requirements for additional customer site preparation work, (4) IOU submission of data reports on a quarterly, rather than biannual, basis to allow tracking of progress on energization projects and to quickly address delays, and (5) clarification if full Commission approval is needed, or if Commission staff is delegated authority, to amend the required data fields in the Energization Target Reporting Template;

- Improve and provide online the Proposed Decision's Appendix C customer complaint form, and establish public accessible tracking of customer complaints;

- Require the IOUs to establish customer energization data portals in addition to adopting the Proposed Decision's customer outreach requirements; and

- Establish a Phase 2 stakeholder working group in addition to the annual workshop required by Public Utilities Code section 933.5(a)(3).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ESTABLISHING TARGET ENERGIZATION TIME PERIODS AND PROCEDURE FOR CUSTOMERS TO REPORT ENERGIZATION DELAYS

California Community Choice Association[1] (CalCCA) submits these opening comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the *Proposed Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays*[3] (Proposed Decision), dated August 12, 2024.

I. INTRODUCTION

The Proposed Decision is a constructive first step to improving customer energization by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDGE), (collectively, the IOUs), as required by Senate Bill (SB)

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[3] Proposed *Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays*, Rulemaking (R.) 24-01-018 (Aug. 12, 2024).

410[4] and Assembly Bill (AB) 50.[5] The inability of IOUs to keep pace with customer energization requests throughout California has increased customer costs and delayed housing, municipal, commercial, and other projects. The Proposed Decision intends to: (1) accelerate energization projects through targets and timelines, (2) ensure robust IOU reporting on projects and details regarding the energization process to inform Phase 2 refinements of the targets and timelines, (3) update customer energization delay complaint procedures, and (4) improve transparency and customer outreach between the IOUs and energization customers. As noted throughout the Proposed Decision, shortcomings in the IOU data responses in Phase 1 limits the ability of the Commission to adequately address all outstanding energization issues. The robust data reporting required by the Proposed Decision is therefore intended to inform the Phase 2 refinements to the energization targets, timelines, customer complaint, and IOU engagement processes.

Community choice aggregators (CCAs) are interested in improving energization timelines and transparency on behalf of their customers and communities. CCAs provide electric generation services and other services to customers. Distribution services are provided by the IOUs, who are also responsible for interconnecting and energizing CCA customers. Many CCAs are working to accelerate building and transportation electrification in their communities to reduce dependence on fossil fuels. CCAs consistently hear concerns from customers regarding significant energization delays and other challenges with the energization process. CCAs, cities,

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[4] SB 410, Stats. 2023, Ch. 394. SB 410 requires the Commission to establish (1) target energization deadlines, (2) IOU annual reporting requirements on compliance with target deadlines, reasons for noncompliance, strategy for improvement, and staffing levels necessary to meet goals, and (3) reporting processes for customer complaints on energization.

[5] AB 50, Stats. 2023, Ch. 317. AB 50 requires the Commission to (1) establish criteria for timely energization, (2) create IOU reporting requirements on fulfillment of timely electric service, (3) hold an annual public workshop with interested parties and experts in customer energization to discuss the IOU reports and needs for revision of the criteria, (4) evaluate the report from IOUs with backlogged projects and ensure the IOUs are taking actions necessary to energize at least 80 percent of the backlog, and (5) ensure the IOUs are improving their projected demand forecasts.

towns, counties, and energy, rural, business, and environmental and climate groups sent a letter to the Legislature on April 26, 2023, stating:

> Severely delayed and abandoned electrical projects are a growing problem in communities throughout California. Hundreds of local projects spanning rural and urban have been delayed or cancelled, including service extensions to new affordable housing units and critical service sites ranging from hospitals to police/fire stations. Hookups for new electric vehicle charging stations and utility-scale and customer-sited renewable energy projects are also in peril.[6]

As an example, the City of San Francisco recently reported 83 active projects with energization delays and increased project costs.[7] Since November 2018, the City of San Francisco reports the total cost impact (additional project costs and loss of revenue) from energization delays as approximately $45 million.[8] The delays impact projects at affordable housing units, libraries, the Muni, academic buildings, fire boats, recreational centers, educator housing, traffic signals and safety streetlights, and water pump stations.

SB 410 and AB 50 address these energization issues, requiring the Commission to adopt various timing and process improvements. Certain energization improvements must be adopted by September 30, 2024, including: (1) reasonable average and maximum target energization time periods, and (2) a procedure for customers to report energization delays to the Commission. This Phase 1 Proposed Decision focuses on these statutory requirements, while also increasing transparency through robust data reporting requirements for the IOUs on the energization

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[6] *Letter from 35 Organizations Urging the California Legislature to Address the State's Interconnection Crisis and Ensure Timely and Equitable Access to the Electrical Grid* (Apr. 26, 2023) (available in Docket No. 23-IEPR-05, attachment to East Bay Community Energy Comments on May 9, 2023 Interconnection Workshop (May 24, 2023)).

[7] *San Francisco Public Utilities Commission Quarterly Report to the Board of Supervisors on the Status of Applications to PG&E for Electric Service* (May 20, 2024), Item 15.h. on San Francisco Public Utilities Commission Regular Meeting Agenda (May 28, 2024).

[8] *Ibid.*

process. Phase 2 will focus on other SB 410 and AB 50 requirements and explore improvements to the Phase 1 adopted requirements.

As described more fully below, CalCCA recommends that the Commission:

- Adopt the Proposed Decision's immediate establishment of statewide targets for Electric Rules 15, 16, 29, 45, and main panel upgrades, and the timelines for projects requiring upstream capacity upgrades;
- Adopt the Proposed Decision's approach to consequences for failure to comply in Phase 1, including finding an IOU out of compliance if five percent or more of an IOU's energization requests are overdue in one year, and monitoring compliance to assess the adoption of additional consequences in Phase 2;
- Refine the Proposed Decision's reporting requirements to ensure increased transparency, including requiring: (1) reporting on all pending and future energization requests, (2) the identification of the load serving entity (LSE) serving a site or project, (3) reporting on IOU requirements for additional customer site preparation work, (4) IOU submission of data reports on a quarterly, rather than biannual, basis to allow tracking of progress on energization projects and to quickly address delays, and (5) clarification if full Commission approval is needed, or if Commission staff is delegated authority, to amend the required data fields in the Energization Target Reporting Template;
- Improve and provide online the Proposed Decision's Appendix C customer complaint form, and establish public accessible tracking of customer complaints;
- Require the IOUs to establish customer energization data portals in addition to adopting the Proposed Decision's customer outreach requirements; and
- Establish a Phase 2 stakeholder working group in addition to the annual workshop required by Public Utilities Code section 933.5(a)(3).[9]

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S IMMEDIATE ESTABLISHMENT OF STATEWIDE TARGETS AND TIMELINES AND CONSEQUENCES FOR FAILURE TO COMPLY

The Commission should adopt the Proposed Decision's standardized, statewide energization metrics for steps within the IOUs' control: (1) average and maximum day **targets** for Electric Rules 15, 16, 29, and 45, and main panel upgrades, and (2) the more flexible and

[9] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

project specific **timelines** for projects requiring upstream capacity upgrades. CalCCA supports the Commission's plan to take this preliminary step in Phase 1 to accelerate IOU energization. The overall lack of consistency and granularity in the IOUs' responses to the data requests in Phase 1 necessitate further exploration of the root causes of energization delays, both within and outside of the IOUs' control. Based on both the IOUs' ability to meet the targets, and the additional data provided by the IOUs on upstream capacity upgrade timelines, the Commission can further refine these statewide targets in Phase 2.

The Proposed Decision also takes a first step towards imposing consequences on the IOUs for failure to meet the targets, which will result in the project being deemed "overdue."[10] An IOU with five percent or more of customer energization requests overdue in one year will "be out of compliance with the Commission's directive."[11] While these Phase 1 consequences lack any penalties for noncompliance, CalCCA agrees with the Commission's approach to first establish these targets and closely monitor through robust data collection whether energization delays are lessened. For the timelines on upstream capacity upgrades, the additional data can lead to the establishment of targets subject to the same consequences. If the IOUs fail to comply with these Phase 1 requirements, the Commission can consider additional compliance requirements and consequences after gathering additional data to better understand the factors leading to delays.

III. THE PROPOSED DECISION'S DATA REPORTING REQUIREMENTS SHOULD BE REFINED TO ENSURE INCREASED TRANSPARENCY

The data requirements adopted in the Proposed Decision should be refined to ensure increased transparency into the causes of energization delays. The Proposed Decision requires the IOUs to jointly develop a data reporting template that aligns with section 933.5(a)(2)(B), the

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[10] Proposed Decision, at 65.

[11] *Ibid*.

new energization targets/timelines, and the "Energization Target Reporting Template Requirements" set forth in the Proposed Decision, Appendix B. As described below, the Commission should require: (1) incorporation into Appendix B of section 933.5 reporting requirements for both pending and future energization requests, (2) identification in the Appendix B data reporting of the LSE serving a particular site or project, (3) reporting on IOU requirements for additional customer site preparation work, (4) IOU submission of data reports on a quarterly, rather than biannual, basis to allow the Commission, customers, and LSEs to track progress on energization projects and to quickly address delays, and (5) clarification if full Commission approval is needed, or if Commission staff is delegated authority, to amend the required data fields in the Energization Target Reporting Template.

A. The Proposed Decision Should Be Revised to Require Section 933.5 Information for both Pending and Future Energization Requests

The Proposed Decision should be revised to ensure <u>all</u> data relevant to the creation and refinement of the criteria for timely energization is considered, as required by AB 50, and codified in section 933.5. The Proposed Decision currently omits relevant data describing pending energization requests from December 2023 to the date of adoption of the Proposed Decision. Section 933.5 requires the Commission to collect and analyze three overall categories of IOU data:

1) **Pre-Phase 1 Decision Data – Section 933.5(d):** Information collected annually by the Commission in the form of a report "to inform the Commission's determination of criteria for timely service," with this requirement becoming inoperative once the Commission establishes reporting requirements pursuant to section 933.5(a);

2) **Post-Phase 1 Decision Data – Section 933.5(a):** Information collected pursuant to the criteria and reporting requirements established by the Commission pursuant to section 933.5(a); and

3) **Energization Backlog Data – Section 933.5(b):** If an IOU had, as of January 31, 2023, energized less than 35 percent of customers with completed applications 12 months or older, that IOU must submit a report by December 1, 2024, demonstrating that 80 percent of customers with completed applications as of January 31, 2023, are energized (and if the IOU does not meet the 80 percent metric, the report must include specific information required by section 933.5(b)(2)).

Rulings dated March 21, 2024,[12] and June 6, 2024,[13] required the IOUs to provide a portion of the Pre-Phase 1 Decision Data required by section 933.5(d) for the January 2019 to December 2023 period. However, no additional Ruling or data request has been issued for the post-December 2023 period. The backlog reporting required by section 933.5(b) does require certain ongoing data on projects with completed applications as of January 31, 2023, but the data required is not as extensive as the section 933.5(d) data.[14]

The Proposed Decision explicitly adopts new reporting requirements (i.e., the biannual reports with the Appendix B data) pursuant to section 933.5(a) for energization projects that have

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[12] *Administrative Law Judge's Ruling Directing Utility Responses to Questions Regarding Energization Timelines,* R.24-01-018 (Mar. 21, 2024), as amended, *Email Ruling Adjusting Phase 1 Schedule and Addressing the April 2, 2024, Joint Investor-Owned Utilities' Motion, Email Ruling Adjusting Phase 1 Schedule and Addressing the April 2, 2024, Joint Investor-Owned Utilities' Motion*.

[13] *Administrative Law Judge's Ruling Directing Parties to Respond to Questions on Energization Issues,* R.24-01-018 (June 6, 2024).

[14] The section 933.5(b) data is required when the IOU energized less than 35 percent of customers, with applications 12 months or older. *See* Pub. Util. Code § 933.5(b)(1). In that case, the IOU is required to report on whether energization of 80 percent of projects is complete by December 1, 2024. *Ibid.* This section 933.5(b) data will therefore not provide information on the 20 percent of projects not energized if the IOU meets the 80 percent threshold. In addition, if the IOU had energized more than 35 percent by January 31, 2023, no section 933.5(b) data is required. Finally, the 2024 data required by section 933.5(b) is different from the section 933.5(d) data. *See id.,* § 933.5(b) (requiring data the IOU to "implement actions necessary to meet the [80%] performance metric and include a summary of these actions in the report submitted to the commission" including number of withdrawn or cancelled applications, aggregated data on the reasons for withdrawal or cancellation, and factors leading to delays outside the IOU's control); *see also id.,* § 933.5(d) (requiring number of submitted, completed, pending and uncompleted requests for energization, time for energization, spending on energization, and other information requested by the commission to evaluate energization).

submitted complete applications beginning on the issuance date of the adopted Decision.[15] In other words, the new data will only include data on projects that submit applications on or after the date of the adopted Decision.

The already obtained data, and the new data the IOUs are required to provide to the Commission will therefore be missing a crucial piece – section 933.5(d) data for projects post-December 2023 and before the Decision is adopted. The Proposed Decision already correctly notes that much of the data provided by the IOUs in response to the ALJ Rulings lacks the consistency or granularity needed for the Commission to adequately set targets and timelines.[16] To thoroughly evaluate the IOU energization processes, CalCCA recommends that any missing section 933.5(d) data from December 2023 through the adoption date of the Decision be added to the list of required Appendix B data.

B. The LSE Serving a Site/Project Should be Included in the Appendix B Data Reporting

Appendix B should be revised to require the identification of LSEs, including CCAs, when data is being collected on a specific site or project. LSEs need to be informed about energization delays that directly affect their customers, impact customer programs, and in some cases, impact the energization of assets under their control or ownership. Many CCAs have launched or are considering programs to encourage the use of electric vehicles (EV), smart

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[15] *See* Proposed Decision, Ordering Paragraph (O¶) 18, at 84 ("The biannual energization reports required in [OP] 17 must reflect data for **all customer energization requests submitted after the issuance of this decision** and will be posted on the Commission's Energization website . . . ." (emphasis added); *id.* at 49 ("The large electric IOUs shall provide data related to all energization projects that have submitted complete applications **beginning on the issuance date of this decision** in their first biannual report filed no later than March 31, 2025.") (emphasis added); *id.* at 65 ("Compliance reports shall be filed by the IOUs every six months to the R.24-01-018 service list, with the first submission required to be served no later than March 31, 2025, and the second no later than September 30, 2025").

[16] *Id.* at 47 ("information provided by the large electric IOUs to date is inadequate to support full implementation of Pub. Util. Code § 933.5(a)(2)(B). While the large electric IOUs collected some of the data necessary to evaluate timeliness of customer energization requests, there are many gaps that must be addressed to ensure statutory compliance").

appliances, or solar plus storage, and to facilitate participation in managed EV charging, load shifting, demand response, and other beneficial programs. These programs can provide resiliency, reduce customer bills, achieve green-house gas reduction goals, and lower power procurement costs. Project delays such as installing panel upgrades or energizing public EV charging stations, however, may discourage customer participation in these programs and could have negative financial implications for CCAs and their customers. The significant energization delays have already increased the burden on CCA customer support resources, given the lack of data and communication about these delays and who is responsible for addressing them. CalCCA therefore recommends that Appendix B be amended to require identification of the LSE serving the customer when data is being collected on a site/project basis. Any summary data should also include both IOU and LSE information, to the extent possible and applicable.[17]

C. IOU Requirements for Additional Customer Site Preparation Work Should be Included in the Appendix B Reporting

Appendix B should be revised to require the IOUs to describe when and why an IOU requires a customer to do site preparation in addition to what was originally planned before the IOU completes electrical construction. This might occur, for example, if conditions on the distribution grid change between the IOU's initial project design (Step 2) and the preconstruction field meeting (Step 5), if additional site improvements are identified during the electrical construction (Step 6), or if an IOU makes an error during the project design step. In such instances, the delay might be categorized as work outside the IOU's control. To ensure accurate reporting and to facilitate improvements in energization timeliness, however, the IOUs should be

[17] For example, the Proposed Decision, Appendix B, Items 10-16, require the IOUs to provide general data on total numbers of energization requests received, approved, and completed, in aggregate and broken down by end-use. The IOUs should be required to identify which of the energization requests are for customers of LSEs other than the IOUs.

required to report such data, with an explanation of why and when in the process the additional work was required.

D. The IOU Data Reports Should Be Submitted Quarterly Rather Than Only Biannually

The IOUs should be required to submit their energization data reports more frequently than the Proposed Decision's biannual requirement.[18] At a minimum, quarterly reports will allow the Commission, customers, and LSEs to track progress on specific energization projects and quickly address delays. In fact, in other proceedings addressing urgent situations, the Commission has required monthly reporting. For example, to track rising arrearages and potential disconnections of customers, the Commission in the Disconnections proceeding required the IOUs to provide monthly disconnections reports.[19] Here, at least quarterly reporting is necessary given the magnitude of the energization backlogs, the significant delays being experienced by customers, and the urgency of accelerating energization times to support the anticipated electric load growth needed to achieve the State's carbon reduction goals.

E. The Commission Should Clarify if Full Commission Approval is Needed to Amend the Required Data Fields in the Energization Target Reporting Template

The Commission should clarify conflicting statements in the Proposed Decision as to whether full Commission approval is required, or if Energy Division staff has been delegated authority, to amend the Energization Target Reporting Template. Section 10 of the Proposed Decision, and Ordering Paragraphs 8 and 16, delegate authority to Commission staff to modify the Energization Target Reporting Template.[20] Conclusion of Law 9, however, states that

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[18] *Id.*, O¶s 17 and 18, at 83-84.

[19] D.18-12-013, *Decision Adopting Interim Rules to Reduce Residential Customer Disconnections for California-Jurisdictional Energy Utilities,* R.18-07-005 (Dec. 13, 2018), O¶ 6, at 31.

[20] Proposed Decision, at 51.

"(a)mendments to the required data fields adopted in Appendix B of this decision, Energization Target Reporting Template Requirements, will require full Commission approval."[21] These conflicting provisions should be clarified in the final decision.

IV. THE PROPOSED DECISION'S APPENDIX C DRAFT CUSTOMER ENERGIZATION DELAY COMPLAINT FORM AND PROCESSES SHOULD BE IMPROVED

A. The Proposed Customer Complaint Form Should Be Provided Online and Simplified for Customers

The Appendix C Customer Energization Complaint Form should be revised to ensure ease of customer use and Commission analysis of the information. First, in addition to allowing a customer to email and mail their complaint with the information required on the form, the Commission should allow the form to be completed online. The online form should have separate fields for each category of data for which the Commission requires a response. The option to fill out and submit the form through an online webpage will make it easier for customers to submit their complaints.

Second, the form assumes customers are familiar with electric tariff rules and understand electric utility jargon, which may be true for developers, contractors, and customers accustomed to working with electric utilities, but may intimidate other customers. Therefore, the form should include further explanatory information regarding the type of projects for which each tariff rule applies. This explanatory information should be provided to customers seeking to file complaints in two formats: (1) clear definitions and explanations of industry terms and requirements in the form itself, and (2) an attached "Frequently Asked Questions" (FAQ) document which clearly explains issues and terms in the form. The FAQ document can provide resources such as hyperlinks and where to find additional relevant information.

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[21] *Id.*, Conclusion of Law (COL) 9, at 76.

Finally, even with a simplified online form, customers who face language, access, or other barriers may need assistance completing and submitting the form. At a minimum, the form should be available in multiple languages. Customers should also be allowed to designate a local agency, such as a CCA, Community Based Organization (CBO), or other third-party to complete and submit a complaint on their behalf.[22]

B. The Commission Should Establish Public Accessible Tracking of Customer Complaints

The Commission should establish a public tracking mechanism for submitted complaints. The Proposed Decision states that Commission staff "does not have the bandwidth to respond to each customer delay complaint on a case-by-case basis, [but that] these collective reports will help identify trends in energization delays, such as the impact geographical locations have on the energization timing."[23] While CalCCA recommends that each customer complaint be individually addressed, if that cannot be achieved the Commission should at least ensure transparency regarding the status of a customer complaint by establishing a public tracking mechanism with anonymized customer information (allowing individual customers to identify their own project). Without a means of checking on status, customers may surmise their complaints are being ignored or may decide not to file a complaint at all.

V. THE COMMISSION SHOULD REQUIRE IOUS TO ESTABLISH CUSTOMER ENERGIZATION DATA PORTALS IN ADDITION TO ADOPTING THE PROPOSED DECISION'S CUSTOMER OUTREACH REQUIREMENTS

The Proposed Decision's detailed requirements for improved customer outreach and transparency from the IOU account/project manager should be adopted.[24] The IOUs that have

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[22] *See California Community Choice Association's Comments on the Administrative Law Judge's Ruling Directing Parties to Respond to Questions on Energization Issues,* R.24-01-018 (June 18, 2024), at 7.

[23] Proposed Decision, at 65.

[24] *Id.* at 53.

not already done so should also be required to create customer energization data portals to enable increased communications and transparency. The Proposed Decision requires the IOUs' "customer-engagement and communication plan" submitted by Tier 1 Advice Letter within 60 days of issuance of the Decision to include a "tool" to notify customers of completion of steps in the energization process.[25] CalCCA recommends the Commission require an automated system or data portal to, at a minimum, display project tracking and allow communications between the customer and account/project manager, similar to the Builder Portal described by SDG&E at the February 2, 2024 Workshop.[26] Such a portal can efficiently provide the services required by the tool along with other customer outreach functions described in the Proposed Decision. Accordingly, in addition to adopting the Proposed Decision's customer outreach requirements, the Commission should require the IOUs that have not already done so to establish customer energization data portals.

VI. THE COMMISSION SHOULD ESTABLISH A PHASE 2 STAKEHOLDER WORKING GROUP IN ADDITION TO THE ANNUAL WORKSHOP REQUIRED BY SECTION 933.5(A)(3)

The Commission should immediately establish a Phase 2 working group to allow Energy Division and stakeholder involvement in the formulation of the Energization Target Reporting Template, as well as ongoing Phase 2 issues. Ordering Paragraph 11 states that "the large electric IOUs shall incorporate any comments from the Commission's Energy Division and parties to this proceeding to refine the template as needed."[27] Rather than wait for parties to comment on a

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[25] *Id.* at 58.

[26] *See SDGE Presentation of Energization Timeline Workshop, Panel 1, Eric Turner, Project Manager – Developer Initiation* (Feb. 2, 2024) (describing functions of the SDGE "Builder Portal" including an online application, project tracking, project checklists, and standards videos), located at: www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/energization/ab50_sb410-energization-workshop_02022024.pdf.

[27] Proposed Decision, O¶ 11, at 82.

Tier 1 Advice Letter to be filed 60 days after the issuance of the Decision, the IOUs, Energy Division, and stakeholders can reach consensus on the template during a working group process. As recommended by CalCCA and many parties in this proceeding, inclusion of stakeholders in a working group will allow industry groups, LSEs, developers, and others to weigh in on quickly improving the energization process, rather than waiting for the annual workshop required by section 933.5(A)(3) and other formal Commission proceedings and comment periods.[28] CalCCA therefore recommends the immediate establishment of a working group to meet on a regular basis to inform the Phase 2 proceedings.

VII. CONCLUSION

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

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 29, 2024

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[28] *See California Community Choice Association's Status Conference Statement,* R.24-01-018 (May 20, 2024), at 3-4 (recommending formation of working group); *Opening Comments of the Alliance for Automotive Innovation on Scoping Memo,* R.24-01-018 (May 3, 2024), at 10 (recommending convening a quarterly working group to "identify bottlenecks and pain points, share information and best practices, and develop solutions to improves energization processes"); *see also Opening Comments of the Interstate Renewable Energy Council, Inc. on the Commissioner's Scoping Memo and Ruling,* R.24-01-018 (May 3, 2024); *Reply Comments of the Interstate Renewable Energy Council, Inc. on the Commissioner's Scoping Memo and Ruling,* R.24-01-018 (May 17, 2024); *Opening Comments of Environmental Defense Fund and Natural Resources Defense Council on Scoping Memo,* R.24-01-018 (May 3, 2024).

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ESTABLISHING TARGET ENERGIZATION TIME PERIODS AND PROCEDURE FOR CUSTOMERS TO REPORT ENERGIZATION DELAYS

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

Proposed text deletions show as **bold and strikethrough**
Proposed text additions show as **bold and underlined1**

FINDINGS OF FACT

4.[29] The data collected through the requirements adopted in Section 10 of this decision, **~~Biannual~~Quarterly** Energization Reporting Requirements can improve the Commission's ability to identify the appropriate amount of future acceleration of the large electric IOUs' energization target(s) in Phase 2 of this proceeding.

21. The data collected pursuant to Section 10 of this proceeding, **~~Biannual~~Quarterly** Energization Reporting Requirements, will include specific information about energization requests within ESJ communities to inform whether additional data should be collected for specific communities.

32. Consistent with Pub. Util. Code § 933.5(2)(B) it is reasonable to direct the large electric IOUs to develop a data reporting template consistent with the steps outlined in Section 10 of this decision, **~~Biannual~~Quarterly** Energization Reporting Requirements, and Appendix B of this decision, Energization Target Reporting Template Requirements.

33. Public comments can improve the **~~biannual~~quarterly** data reporting template as required in in Section 10 of this decision, **~~Biannual~~Quarterly** Energization Reporting

[29] The Proposed Decision omitted numbering of the Findings of Fact. CalCCA is providing numbers based on the ordering of the Findings of Fact included in the Proposed Decision for convenience.

Requirements, and Appendix B of this decision, Energization Target Reporting Template Requirements. Public comments may identify potential revisions to the proposed data reporting template before the large electric IOUs' initial ~~**biannual**~~**quarterly** energization reports are filed.

CONCLUSIONS OF LAW

5. The energization target reporting template directed in Section 10 of this decision, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, can incorporate party feedback before the large electric IOUs file their first ~~**biannual**~~ **quarterly**energization reports.

6. To comply with Pub. Util. Code § 933.5(a)(3), the large electric IOUs should host a public workshop within 90 days of submitting their initial ~~**biannual**~~**quarterly** data, due March 31, 2025, to the Commission.

ORDERING PARAGRAPHS

4. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must comply with the data reporting requirements set forth in Section 10, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, and Appendix B, Energization Target Reporting Template Requirements, as adopted in this decision.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must submit a Tier 1 Advice Letter no later than 60 days after the issuance of this decision that proposes a consolidated reporting template to track the data requirements listed in Section 10, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, and Appendix B, Energization Target Reporting Template Requirements, as adopted in this decision.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall ensure the data collection template proposed pursuant to Section 10 of this decision, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, and

Appendix B of this decision, Energization Target Reporting Template Requirements, aligns with the goals of the Commission's Environmental and Social Justice Action Plan.

10. The proposed data collection template directed in Section 10 of this decision, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, and Appendix B of this decision, Energization Target Reporting Requirements, shall provide clear descriptions of the strategies Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the large electric investor-owned utilities (IOU)) will employ to engage local and tribal governments to ensure their energization processes are clear to all customers.

11. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the large electric investor-owned utilities (IOU)) must jointly file and serve the proposed data template, as required in Section 10 of this decision, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements, via a Tier 1 Advice Letter on the service list for Rulemaking (R.) 24-01-018 no later than 60 days after the issuance of this decision. The large electric IOUs shall incorporate any comments from the Commission's Energy Division and parties to this proceeding to refine the template as needed. The reporting template shall include the full list of data required to be collected as provided in Appendix B, Energization Target Reporting Template Requirements. The large electric IOUs must submit the final template with recorded data in their first annual Tier 1 Advice Letter no later than March 31, 2025.

12. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall provide information about energization projects that trigger, are delayed by, or are cancelled due to an identified upstream capacity upgrade in their

~~**biannual**~~**quarterly** reports filed pursuant to Section 10 of this decision, ~~**Biannual**~~**Quarterly** Energization Reporting Requirements.

16. The California Public Utilities Commission's Energy Division is authorized to make any necessary updates to the ~~**biannual**~~**quarterly** energization target reporting template upon review of the initial reports from Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, if staff determines that changes are necessary to improve data collection prior to the next decision in this proceeding.

17. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file and serve ~~**biannual**~~**quarterly** energization reports to the California Public Utilities Commission every ~~**six**~~**three** months to demonstrate compliance with the statewide targets outlined in Section 7, Energization Targets, of this decision, with the first ~~**biannual**~~**quarterly** energization data report filed and served to the service list of Rulemaking 24-01-018 by March 31, 2025~~**, and the second by September 30, 2025**~~.

18. The ~~**biannual**~~**quarterly** energization reports required in Ordering Paragraph 17 must reflect data for all customer energization requests submitted after the issuance of this decision and will be posted on the Commission's Energization website, for the purposes of improving Commission, customer, and party insight into energization delays occurring in the large electric investor-owned utility service territories.

NEW CONCLUSIONS OF LAW

X. Creating an online customer complaint form and establishing publicly accessible tracking of customer complaints will improve transparency and meet requirements established in AB 50 and SB 410.

X. IOU data portals will provide greater transparency for customers to track energization progress and fulfill the customer notification requirements established in Section 12 of this decision, Improved Customer Outreach.

X. A working group process will facilitate stakeholder input in the formulation of the Energization Target Reporting Template, as well as ongoing Phase 2 issues.

NEW ORDERING PARAGRAPHS

X. The California Public Utilities Commission's Energy Division shall establish an online Customer Complaint Form consistent with the requirements outlined in Section 11, Customer Reporting Procedures, and Appendix C, Draft Customer Complaint Form, as adopted in this decision. Energy Division shall establish publicly accessible tracking of customer complaints using data collected from this online Customer Complaint Form.

X. The large IOUs that have not already done so shall each establish customer energization data portals as part of their customer-engagement and communication plan. These data portals shall fulfill the customer notification requirement described in Section 12, Improved Customer Outreach, as adopted in this decision.

X. **The California Public Utilities Commission's Energy Division shall establish a working group process to allow Energy Division and stakeholder involvement in the formulation of the Energization Target Reporting Template, as well as ongoing Phase 2 issues. The first meeting of this working group shall take place no later than 30 days after the issuance of this decision.**

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ALLOWING BRIDGE RESOURCES FOR ALTERNATIVE COMPLIANCE WITH DIABLO CANYON REPLACEMENT RESOURCE CATEGORY IN DECISION 21-06-035

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August 29, 2024

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California Public Utilities Commission Rulings

Administrative Law Judge's Ruling Seeking Comments on Staff Proposal to Allow Temporary Bridge Resources to Meet Diablo Canyon Replacement Obligations, R.20-05-003 (May 21, 2024) 2

SUMMARY OF RECOMMENDATIONS

- The Proposed Decision provides a well-balanced solution that supports system reliability and ratepayer cost savings while carefully addressing the current realities of the procurement of new resources, in which project delays can happen that threaten load-serving entity compliance despite their best efforts to comply. The California Public Utilities Commission should adopt the Proposed Decision.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ALLOWING BRIDGE RESOURCES FOR ALTERNATIVE COMPLIANCE WITH DIABLO CANYON REPLACEMENT RESOURCE CATEGORY IN DECISION 21-06-035

The California Community Choice Association (CalCCA)[1] submits these opening comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Allowing Bridge Resources for Alternative Compliance With Diablo Canyon Replacement Resource Category in Decision 21-06-035*[3](Proposed Decision), dated August 9, 2024.

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[3] Proposed *Decision Allowing Bridge Resources for Alternative Compliance With Diablo Canyon Replacement Resource Category in Decision 21-06-035*, Rulemaking (R.) 20-05-003 (Aug. 9, 2024): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=537639351.

This decision allows load-serving entities (LSEs) with compliance obligations in Decision (D.) 21-06-035[4] as part of the category of resources designed to replace the attributes of the Diablo Canyon Power Plant (DCPP), to use short-term alternative compliance options as defined in the Proposed Decision.

I. INTRODUCTION

CalCCA applauds the Commission for developing creative compliance options that will support reliability and affordability objectives while recognizing procurement realities that make it difficult to predict delays and bring all resources online on schedule despite reasonable efforts. Considering the "very challenging procurement environment" in which "LSEs were not likely to meet their requirements for Diablo Canyon replacement resources in time" for the June 1, 2025, compliance deadline,[5] the Proposed Decision approves the option for LSEs to use bridge capacity resources for no more than three years to count towards the requirements. The Proposed Decision finds that allowing bridge capacity to meet the DCPP replacement requirement has the potential for ratepayer cost savings and short-term reliability benefits.[6]

CalCCA did not take a position on the staff proposal[7] because system reliability and affordability impacts will depend on (1) the unique position of LSEs and their DCPP replacement resources procurement progress, and (2) the proposal's impact on the Resource

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[4] D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 24, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

[5] Proposed Decision at 3.

[6] Conclusion of Law (COL) 1 and COL 2.

[7] *Administrative Law Judge's Ruling Seeking Comments on Staff Proposal to Allow Temporary Bridge Resources to Meet Diablo Canyon Replacement Obligations*, R.20-05-003 (May 21, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K042/532042838.PDF.

Adequacy (RA) market, which is currently facing significant scarcity.[8] However, CalCCA supports the Commission in taking creative steps to allow alternative ways to comply with requirements that could be very difficult to achieve in the current market. Issues causing project delays, such as supply chain, permitting, and interconnection, have not been resolved and could continue to impact development timelines unexpectedly or without time for replacement. For these reasons, CalCCA recommends the Commission adopt the Proposed Decision.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION

The Proposed Decision reflects the Commission's efforts to craft a well-balanced solution that carefully addresses the current realities of the market for new resources, in which project delays can happen that threaten LSE compliance despite their best efforts to comply. Community choice aggregators (CCA) understand the urgent need to bring new resources online to increase capacity on the grid, alleviate current constraints on the RA market, and support the transition to clean electricity, and have signed over 16 gigawatts of long-term contracts for clean resources. At the same time, all LSEs and developers face risks in getting new capacity online as scheduled, including interconnection delays, supply chain issues, permitting challenges, and others.

CalCCA supports the Proposed Decision's recognition that:

> In the event of an unexpected last-minute delay to a Diablo Canyon replacement resource coming online, the LSE may be unable to act quickly enough to substitute a bridge resources... we emphasize that Commission staff will assess an LSE's compliance status holistically, considering all of the LSE's efforts to procure resources and taking last-minute delay notices from developers into account.[9]

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[8] *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Staff Proposal to Allow Temporary Bridge Resources to Meet Diablo Canyon Replacement Obligations*, R.20-05-003 (June 21, 2024), at 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K357/534357081.PDF.

[9] Proposed Decision at 16.

The optionality provided by the Proposed Decision and the commitment to reviewing LSE procurement efforts when assessing compliance is necessary in circumstances where it is not possible for all LSEs to comply with their procurement obligations due to factors outside of their control despite reasonable efforts. For these reasons, the Commission should adopt the Proposed Decision and continue to find creative ways across its proceedings to provide such optionality and review compliance status based on a holistic review of LSE efforts when warranted.

The Proposed Decision finds that "[b]ased on reliability analysis and production cost modeling conducted by Commission staff to inform various decisions, including the PSP portfolio adopted in D.24-02-047,[10] 2025 is expected to be a tight year from an electric reliability perspective, even with Diablo Canyon still online."[11] CalCCA agrees with this finding and highlights that using bridge capacity to meet DCPP replacement requirements in this interim period may exacerbate the already tight RA market, which has resulted in procurement challenges and extremely high prices.[12] However, the Proposed Decision also finds that "many LSEs have represented that complying with the Diablo Canyon replacement category of resources in D.21-06-035 has been difficult and could be expensive."[13] By offering flexibility in the ways LSEs can comply with their obligations, the Commission recognizes the negative ratepayer impact of rigid compliance obligations that do not consider procurement realities. The Proposed Decision strikes a reasonable balance, given the realities of the RA and IRP

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[10] D.24-02-047, *Decision Adopting 2023 Preferred System Plan and Related Matters, and Addressing Two Petitions for Modification*, R.20-05-003 (Feb. 15, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF.

[11] Finding of Fact (FOF) 2.

[12] *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs* (Updated Jan. 16, 2024): https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf.

[13] FOF 4.

compliance programs, by introducing the bridge capacity option and maintaining eventual compliance with D.21-06-035 with new resources.

III. CONCLUSION

CalCCA appreciates the opportunity to submit these opening comments on the Proposed Decision, which allows for compliance optionality while accounting for reliability needs and ratepayer impacts. For these reasons, CalCCA respectfully requests the adoption of the Proposed Decision.

Respectfully submitted,

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

August 29, 2024

METRICS

All metrics should be displayed on the DG Stats website at the program level by LSE. The end user may have the option to aggregate and view the program metrics by service territory, LSE, or any other groupings deemed appropriate in design meetings. Upon more in depth discussion with the PAs, the vendor and E.D. the PAs submit that the information below may change in order to best serve the reporting needs of the program.

Data Category	Metric	Definition	Format/Display	Cadence	DAC-GT	CSGT	ECR	Modified GT	CREP
Program - Capacity	Program Cap	Maximum number of MWs designated for program	Number	N/A	X	X	X	X	X
Program - Cost	Annual program costs	Total program costs for the year based on actuals	Number	Annually	X	X	X	X	X
Program - Projects	Projects procured (aka "Projects approved")	Total number of executed project PPAs approved by the Commission	Number	Quarterly	X	X	X	X	X
Program - Capacity	MWs procured	MWs procured, defined as PPAs approved by the Commission	Number	Quarterly	X	X	X	X	X
Program - Projects	Projects online (aka "Projects completed")	Total number of dedicated projects online	Number	Quarterly	X	X	X	X	X
Program - Capacity	MWs online	Dedicated MWs online	Number	Quarterly	X	X	X	X	X
Program - Capacity	Annual program generation	Total generation of all online projects combined in MWh	Number	Annually	X	X	X	X	X
Program - Capacity	Annual Unsubscribed MWh	Number of unsubscribed MWhs, derived from total program generation minus participant usage/ RECs retired	Number	Annually	X	X	X	X	TBD
Program - RECs	Annual MWh of Participant Usage	Total number of MWhs served to participants	Number	Annually	X	X	X	X	X
Program - RECs	Annual MWh of RPS/interim RECs retired for participants	Total number of RPS RECs in MWhs that come from interim resources retired to serve participants	Number	Annually	X	X	-	X	TBD
Program - RECs	Annual MWh of Programmatic/dedicated RECs retired for participants	Total number of Programmatic RECs in MWhs that come from dedicated resources retired to serve participants	Number	Annually	X	X	X	X	TBD
Program - Subscriber	Number of customers enrolled	Total number of customers (service agreements) currently enrolled in the program	Number	Quarterly	X	X	X	X	X
Program - Subscriber	MWs Enrolled	Number of MWs enrolled in program	Number	Quarterly	X	X	X	X	X
Program - Subscriber	Number of low-income customers enrolled	Total number of customers enrolled in low-income customer programs (e.g., CARE/FERA)	Number	Quarterly	X	X	-	-	X
Program - Subscriber	Number of new low-income customers enrolled in CARE/FERA at the time of program enrollment	Number of new low-income customer enrollments in CARE or FERA in the process of enrolling in the program	Number	Quarterly	-	X	-	-	-
Program - Subscriber	Average customer monthly discount	Average monthly bill discount provided to customers based on actuals	Number	Annually	X	X	-	-	X
Program - Subscriber	CSGT master-metered accounts	The total number of master-metered accounts participating in the CSGT Program	Number	Quarterly	-	X	-	-	-
Program - Subscriber	CSGT master-metered capacity	The total capacity, in MWs, allocated to master-metered accounts participating in the CSGT Program	Number	Quarterly	-	X	-	-	-

FIELDS

FIELDS

All data sent to the vendor will be either at the project level, or overall program level. It is still TBD whether granular level customer data should be sent to the vendor and what value that would provide. Upon more in depth discussion with the PAs, the vendor, and E.D the PAs submit that the information below may change in order to best serve the reporting needs of the program.

Data Category	Field	Definition	Format/Display	Cadence	DAC-GT	CSGT	ECR	Modified GT	CREP	Source	Notes
Program - Cost	Annual program costs	Total program costs for the year based on actuals	Number	Annually	X	X	X	X	X	suggested by ED	
Program - RECs	Annual MWh of Participant Usage	Total number of MWhs served to participants	Number	Annually	X	X	X	X	X	D.24-05-065 pp.129-130	
Program - RECs	Annual MWh of RPS/interim RECs retired for participants	Total number of RPS RECs in MWhs that come from interim resources retired to serve participants	Number	Annually	X	X	-	X	TBD	D.24-05-065 pp.129-130	
Program - RECs	Annual MWh of Programmatic/dedicated RECs retired for participants	Total number of Programmatic RECs in MWhs that come from dedicated resources retired to serve participants	Number	Annually	X	X	X	X	TBD	D.24-05-065 pp.129-130	
Program - Subscriber	Number of customers enrolled	Total number of customers (service agreements) currently enrolled in the program	Number	Quarterly	X	X	X	X	X	suggested by ED	Will need to determine how best to send subscriber information to vendor (i.e. do we send individual subscriber level data or aggregate the data and provide whole figures).
Program - Subsciber	MWs Enrolled	Number of MWs enrolled in program	Number	Quarterly	X	X	X	X	X	suggested by PAs	This is a forecasted number. PAs should align on calculation.
Program - Subscriber	Number of low-income customers enrolled	Total number of customers enrolled in low-income customer programs (e.g., CARE/FERA)	Number	Quarterly	X	X			X	suggested by PAs	
Program - Subscriber	Average customer monthly discount	Average monthly bill discount provided to customers based on actuals	Number	Annually	X	X	-	-	X	suggested by ED	Further discussion between PAs and vendor will be needed to determine how best to display this metric (i.e. in dollars or as a percentage of average bill, or both etc.) Additionally, certain requirements should likely be met for including the customer in the average bill discount calculation (ex: minimum length of enrollment, etc.).
Program - Subscriber	CSGT master-metered accounts	The total number of master-metered accounts participating in the CSGT Program	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	This information addresses "subscriber information" as required in OP 6.
Program - Subscriber	CSGT master-metered capacity	The total capacity, in MWs, allocated to master-metered accounts participating in the CSGT Program	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	This information captures "subscriber information" as required in OP 6.
Project - General	Project name	The name of the project as presented in the contract or other official documents	Text	Quarterly	X	X	X	X	X	suggested by PAs	
Project - General	Project facility status	Overall project facility status: In Development: A PPA has been signed and the project is being developed. Projects should have an Overall Project Status of "In Development" if they have a Facility Status of "Online-Partially Delivering", or have a Facility Status of "Online-Fully Delivering" but have not yet started the delivery term. Online: All phases of the Project are online and delivering energy, and the delivery term has commenced. Terminated: Project was terminated at any point after execution and prior to completing the delivery term under the PPA. Expired: Project expired after being online and completing the delivery term under the PPA.	Text	Quarterly	X	X	X	X	X	D.24-05-065 OP6	
Project - Capacity	Project capacity	Project capacity in MW	Number	Quarterly	X	X	X	X	X	D.24-05-065 OP6	
Project - Capacity	Annual project generation	Total generation of project in MWh	Number	Annually	X	X	X	X	X	suggested by PAs	
Project - Techonology	Project technology	Project technology (ex: solar, storage)	Text	Quarterly	X	X	X	X	X	suggested by PAs	Analysis of how this data should be sent to the vendor will be needed since one project can potentially have more than 1 technology (ex: solar + storage).
Project - Location	City	City of project location	Text	Quarterly	X	X	X	X	X	D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
Project - Location	State	State of project location	Text	Quarterly	X	X	X	X	X	D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
Project - Location	Zip Code	Zip code of project location	Text	Quarterly	X	X	X	X	X	D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
Project - Subscriber	Project Sponsors subscribed	Verification if each CSGT Project's Sponsor is receiving energy from that project	Text	Quarterly	-	X	-	-	-	D.24-05-065 OP6	Project Sponsors can elect to receive energy from the CSGT project they are sponsoring. Verification that the CSGT Project Sponsor is receiving energy from the CSGT Project will be reported as "Yes" or "No". This information addresses "subscriber information" as required in OP 6.
Project - Subscriber	Project Sponsor subscription size	Size of each Project Sponsor's subscription, per CSGT project, in MW	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	Project Sponsors can elect to receive energy from the CSGT project they are sponsoring. This information addresses "subscriber information" as required in OP 6.
Project - Subscriber	Number of low-income qualified customers enrolled	Total number of customers enrolled in low-income qualified customer programs (e.g., CARE/FERA) per CSGT project	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	This information addresses "coordination with low-income... programs" as required in OP 6.
Project - Community	Job training	The number of workers registered in a State of California approved apprenticeship program, per CSGT project.	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	This information addresses "job training" as required in OP 6.
Project - Community	Local hiring	The number of workers whose place of residence is located within a 25- mile radius of the CSGT project.	Number	Quarterly	-	X	-	-	-	D.24-05-065 OP6	This information addresses "local hiring" as required in OP 6.

Source	Notes
suggested by PAs	Program cap can be provided one time and updated as needed with the vendor.
suggested by ED	
D.24-05-065 OP6	
suggested by PAs	
D.24-05-065 OP6	May want to have the option to display this by technology type
suggested by PAs	May want to have the option to display this by technology type
suggested by PAs	
D.24-05-065 pp.129-130	This metric is derived from total generation less participant usage, so there is no need to send this data to the vendor; therefore it is not listed in the "Fields" table below.
D.24-05-065 pp.129-130	
D.24-05-065 pp.129-130	
D.24-05-065 pp.129-130	
suggested by ED	The number of customers enrolled may need to be segmented by a customer type (example, low income, or res/non res) depending on the program. This will be discussed in more detail with the vendor and needed data elements provided.
suggested by PAs	This is a forecasted number. PAs should align on calculation.
suggested by PAs	
suggested by PAs	
suggested by ED	Further discussion between PAs and vendor will be needed to determine how best to display this metric (i.e. in dollars or as a percentage of average bill, or both etc.) Additionally, certain requirements should likely be met for including the customer in the average bill discount calculation (ex: minimum length of enrollment, etc.).
D.24-05-065 OP6	This information addresses "subscriber information" as required in OP 6.
D.24-05-065 OP6	This information addresses "subscriber information" as required in OP 6.

Source	Notes
suggested by ED	
D.24-05-065 pp.129-130	
D.24-05-065 pp.129-130	
D.24-05-065 pp.129-130	
suggested by ED	Will need to determine how best to send subscriber information to vendor (i.e. do we send individual subscriber level data or aggregate the data and provide whole figures).
suggested by PAs	This is a forecasted number. PAs should align on calculation.
suggested by PAs	
suggested by ED	Further discussion between PAs and vendor will be needed to determine how best to display this metric (i.e. in dollars or as a percentage of average bill, or both etc.) Additionally, certain requirements should likely be met for including the customer in the average bill discount calculation (ex: minimum length of enrollment, etc.).
D.24-05-065 OP6	This information addresses "subscriber information" as required in OP 6.
D.24-05-065 OP6	This information captures "subscriber information" as required in OP 6.
suggested by PAs	
D.24-05-065 OP6	
D.24-05-065 OP6	
suggested by PAs	
suggested by PAs	Analysis of how this data should be sent to the vendor will be needed since one project can potentially have more than 1 technology (ex: solar + storage).
D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
D.24-05-065 OP6	This project level data can be displayed or summarized as desired in coordination with the vendor.
D.24-05-065 OP6	Project Sponsors can elect to receive energy from the CSGT project they are sponsoring. Verification that the CSGT Project Sponsor is receiving energy from the CSGT Project will be reported as "Yes" or "No". This information addresses "subscriber information" as required in OP 6.
D.24-05-065 OP6	Project Sponsors can elect to receive energy from the CSGT project they are sponsoring. This information addresses "subscriber information" as required in OP 6.
D.24-05-065 OP6	This information addresses "coordination with low-income... programs" as required in OP 6.
D.24-05-065 OP6	This information addresses "job training" as required in OP 6.
D.24-05-065 OP6	This information addresses "local hiring" as required in OP 6.

Connor Flanigan
Managing Director, State Regulatory Operations

August 29, 2024

ADVICE 5361-E
(Southern California Edison Company - U 338-E)

ADVICE 7361-E
(Pacific Gas and Electric Company - U 39-E)

ADVICE 4497-E
(San Diego Gas and Electric Company - U 902-E)

ADVICE 51-E
(Ava Community Energy)

ADVICE 31-E
(Clean Power Alliance of Southern California)

ADVICE 32-E
(CleanPowerSF)

ADVICE 31-E
(Lancaster Choice Energy)

ADVICE 81-E
(Marin Clean Energy)

ADVICE 37-E
(Peninsula Clean Energy)

ADVICE 26-E
(Pico Rivera Innovative Municipal Energy)

ADVICE 23-E
(San Diego Community Power)

ADVICE 24-E
(San Jacinto Power)

ADVICE 38-E
(San Jose Clean Energy)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

P.O. Box 800 8631 Rush Street Rosemead, California 91770 (626) 302-6411

SUBJECT: Joint Submittal Outlining Workshop Results and Process Improvements Pursuant to Ordering Paragraph 8 of Decision 24-05-065.

PURPOSE

In accordance with Ordering Paragraph (OP) 8 of Decision (D.) 24-05-065 (the Decision), Southern California Edison Company (SCE) submits this advice letter on behalf of itself, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (together, the Investor-Owned Utilities (IOUs)) and Clean Power Alliance of Southern California (CPA), CleanPowerSF, CalChoice,[1] Ava Community Energy (Ava), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), San Jose Clean Energy (SJCE) and San Diego Community Power (SDCP) (together, the participating CCAs) to provide workshop results and propose the format and specific data to be included in the California Distributed Generation Statistics (DGStats) reporting website.

BACKGROUND

On May 31, 2022, the IOUs each filed an application for review of their Disadvantaged Community – Green Tariff (DAC-GT), Community Solar Green Tariff (CSGT), and Green Tariff Shared Renewables (GTSR) programs pursuant to D.18-06-027 and D.21-12-036. These applications were consolidated into one proceeding. The Administrative Law Judge (ALJ) issued a Scoping Memo and Ruling on December 2, 2022, which established the scope and schedule for the proceeding including providing the opportunity for stakeholders to propose modifications to existing tariffs or establishing a new tariff or program, if doing so would be beneficial to ratepayers.

On May 30, 2024, the California Public Utilities Commission (CPUC or Commission) adopted the Decision modifying and streamlining existing Green Access Programs (GAP) and adopting a Community Renewable Energy (CRE) Program, pursuant to Assembly Bill (AB) 2316 (Ward, Stats. 2022) and Pub. Util. Code Section 769.3.

On July 19, 2024, the IOUs and participating Community Choice Aggregators (CCA) facilitated a workshop with Energy Division (ED) and relevant stakeholders to determine the format and specific data to be included in the California Distributed Generation Statistics (DGStats) website reporting pursuant to Decision OP 7.

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[1] CalChoice acts as program administrator for Lancaster Choice Energy (LCE), Pico Rivera Innovative Municipal Energy (PRIME), and San Jacinto Power (SJP).

Pursuant to Decision OP 8, within 45 days after facilitating the workshop, noted above, the IOUs and participating CCAs submit this joint Tier 1 Advice Letter outlining the agreed upon data reporting and any efforts planned to better coordinate amongst the various Program Administrators (PAs) and to automate the data collection and transfer process.

DISCUSSION

Overview of DGStats

The Commission ordered the creation of the California Solar Statistics website in 2006 to serve as the official public reporting site for the California Solar Initiative (CSI).[2] In 2015, recognizing the benefits of hosting distributed generation data beyond CSI and Net Energy Metering solar statistics, ED worked with the IOUs to create the new DGStats website and to transfer data from California Solar Statistics to DGStats. Further Commission decisions and ED guidance directed the IOUs to begin publishing to DGStats project-level data from the Self-Generation Incentive Program (SGIP), Solar on Multifamily Affordable Housing (SOMAH) Program, and New Solar Homes Partnership (NSHP).[3] In October 2019, the Commission adopted Resolution E-5030 authorizing ED to oversee contracts for work required to maintain and expand the DGStats website. ED is authorized to define future scopes of work, manage contract deliverables, and set funding levels for the site.[4]

Workshop Summary and Green Access Programs Reporting Overview

As referenced above, the PAs facilitated a workshop on July 19, 2024 (the July Workshop) to determine the format and specific public, non-confidential data to be included in the DGStats website reporting, including specific metrics identified in OP 6 of the Decision.[5] At the workshop, SCE, the singular PA for the discontinued ECR program and CPA the singular PA for the discontinued CSGT program proposed that although not required by the Decision, metrics for both of these closed programs should be reported on the DGStats website for completeness. There were no objections from ED or other stakeholders.

The following discussion proposes metrics to be included in future DGStats reporting for all of the Green Access Programs (GAP), which include the modified DAC-GT and

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[2] D.06-01-024, Interim Order Adopting Policies and Funding for the California Solar Initiative, R.04-03-017 (Jan. 17, 2006).

[3] D.17-12-022, Decision Adopting Implementation Framework for Assembly Bill 693 and Creating the Solar on Multifamily Affordable Housing Program, R.14-07-002 (Dec. 18, 2017)

[4] R. E-5030, Authorizing Energy Division to Oversee Contracts for Work Required to Maintain and Expand the California Distributed Generation Statistics Website (October 24, 2019)

[5] *Id*. at 173 (OP 7).

CSGT programs, the modified GT and ECR programs, and the CRE Program. The cadence in which metrics should be reported after the DGStats website is updated and live, in addition to plans for interim period reporting prior to the transition to the updated DGStats website are also addressed.

As discussed in the July Workshop, specific metrics under consideration include those directed by OP 6 of the Decision, metrics currently reported to the Commission in existing program-related reports, and additional metrics suggested by ED or the PAs.

Given the similarities between programs, the PAs present metrics, reporting cadences, interim reporting, and other concepts which are applicable to all programs in the "Green Access Programs Reporting" section below and provide more detail about each program, its current metrics, and any specific program reporting needs in the "Program Reporting Specifics" section.

Through workshop discussions and further conversation after the workshop, the PAs reached alignment on GAP reporting on the DGStats website. However, all PAs and ED acknowledged that more in depth discussions will need to occur to build out a successful reporting platform for each program on DGStats. These discussions with the DG Stats website vendor, ED and participating PAs are likely to lead to further refinement and/or potential additions, reductions, or changes to reporting metrics. Therefore, the information presented below should be treated only as an initial foundation for future discussions with the vendor and ED, and not as a final design document nor as a scope of work.

Green Access Programs Reporting

In Appendix A-2, the PAs have included a matrix that shows PA by GAP to understand which PA will be reporting on which GAP on the DGStats website.

The PAs propose that GAP data provided to the DGStats vendor by each load serving entity (LSE) be LSE-specific. This will allow the data to be presented on the DGStats website either by LSE, aggregated for the purposes of reporting statewide figures, or through another level of aggregation as determined by the vendor, ED, and reporting PAs in future implementation discussions.

Metrics vs. Fields

Two tables are presented in Appendix A-1: one that lists GAP metrics and one that lists GAP fields. The "Metrics" table presents metrics that are agreed upon as prime candidates for reporting on the DGStats website by program. The PAs define a metric as a measure of quantitative assessment used to track performance of a program.

The PAs further agree that all metrics displayed on the DG Stats website should be presented at the "program" level, as opposed to the "project" level. To illustrate the difference between a program and a project, we can consider that one program such as

DAC-GT will consist of multiple projects. A project is a single contract for the installation of renewable resources by a developer to support a program. Given this hierarchical and one to many relationship between a program and projects, the PAs agree that displaying metrics at the program level provides the correct amount of granularity, while still allowing the end user to aggregate that programmatic data in various ways (i.e., by LSE, service territory, zip code, etc.). To further illustrate the relationship between a program and a project, we can look at how the PAs intend to measure program capacity. Program capacity is a metric that would consist of the sum of each projects' capacity dedicated to a given program, such as DAC-GT. However, only the program level total would be displayed, not the individual project MWs that make up the total.

Naturally, metrics from one program should not be compared to metrics from another program.

The PAs core programmatic metrics fall into five broad categories as shown below:

1. Cost
2. Capacity
3. Subscriber
4. Projects
5. RECs

In addition to programmatic reporting, the CSGT program is the one program that intends to display "project" level information on the DG Stats website. Due to the fact that there are only four total projects in the CSGT program, providing "project" level information is digestible and adds value. These differences for the CSGT program will be detailed in the "Program Reporting Specifics" section under "CSGT Reporting."

In contrast to "metrics", a "field" is defined as a data element that refers to an attribute or property about the entity (i.e., program, project, customer etc.) in question. In some cases, fields may need to be provided to the vendor to help display a metric in a meaningful way. In other cases, the metric itself is the value in a field.

In the "Fields" table shown in Appendix A-1, the PAs present fields as a building block that can be leveraged in initial discussions with the vendor and to ensure all required information is captured appropriately (i.e., project level information). For simplicity, fields are given the same five categories referenced above, with the addition of community, technology, and location. However, sometimes these categories relate to a project instead of a program, as opposed to "Metrics" which all relate to a program. The PAs understand that future discussions with the vendor will be necessary to ensure the data (fields) are transferred to the vendor in the correct format and at the correct level of granularity for successful reporting and that ensures data confidentiality.

The PAs propose that the following metrics be included for the DAC-GT, CSGT, modified GT, ECR, and CRE programs on the DGStats website in accordance with the

Decision. Additional information, including the specific definition for each category discussed below is included in Appendix A-1.

Programmatic Information – Cost

During the July Workshop, Energy Division staff recommended that the DGStats reporting include annual program costs. The PAs support including this metric on the DGStats website for all programs.

The proposed programmatic cost-related metric for the GAP programs is summarized as the following:

1. Annual program costs

Programmatic Information – Capacity

All parties agreed that program capacity is an important measure for public visibility. Additionally, PAs agreed that in some cases, such as when comparing the program cap in MW to the number of MWs online for a program in a given quarter, “MWs online” is the preferred metric. However, in other cases, such as at the end of the year, once the PAs have access to the total amount of energy a program has generated for the year as well as the corresponding amount of energy program participants have consumed in that year, it can be more valuable to look at capacity in terms of energy (i.e. MWhs). Therefore, the PAs propose collecting and presenting both MWs and MWhs associated with each program on the DG Stats website.

The proposed programmatic capacity-related metrics for the GAP programs are summarized as the following:

1. Program Cap
2. MWs procured
3. MWs online
4. Annual program generation (MWh)
5. Annual Unsubscribed MWh

Programmatic Information – Subscriber

The PAs propose that the “subscriber information” requested in OP 6 of the Decision[6] is represented by the number of enrolled customers and average monthly discounts provided to those customers as applicable.

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[6] *Id*. at 173 (OP 6).

Additionally, during the July Workshop, ED suggested subscriber information include the "number of customers enrolled". PAs determined that the number of customers enrolled should always be reported at the lowest level of granularity available to define a customer (i.e., the electric service agreement level). All PAs agreed they are reporting at the service agreement level in their current reporting and should continue to do so.

Parties at the workshop further acknowledged that different programs may have different needs to segment the number of customers enrolled by different customer characteristics. Different ways to segment the number of customers enrolled could include, but are not limited to, customer class, low-income status, business type, or Title 24 compliance driven enrollments. Parties agreed that further discussions will be needed by all participating PAs within a program to identify the most meaningful ways to segment customers for any given program.

In addition, to provide an overall snapshot of the degree to which the program has been enrolled or subscribed to by customers, the PAs suggest including the number of enrolled customers presented in MW. The creation of this metric typically requires some type of forecast in terms of future customer usage as well as a general capacity factor to apply to the MWs of generation online. PAs agree that the methodology used to arrive at the MWs of customers enrolled as well as any assumed inputs to this calculation should be discussed and agreed upon by the PAs and ED. Any divergences from methodologies among PAs, if at all, should be minimal to ensure comparisons across PAs are valid and appropriate.

OP 6 further contemplates reporting on the coordination with low-income and clean energy programs. With regard to low-income programs, as noted above, where appropriate, (potentially in a program such as the CRE Program), PAs intend to report on the number of customers enrolled in low-income programs, which for most programs would be the total number of enrolled customers by California Alternate Rates for Energy (CARE) and/or Family Electric Rate Assistance (FERA) program status. "Coordination with low-income programs" for programs, like DAC-GT or CSGT, means reporting on the number of new CARE/FERA enrollments in the process of enrolling customers in the program on a quarterly basis[7]. Though this metric remains relevant for CSGT, it is no longer as relevant for DAC-GT, as PAs move to implement auto-enrollment processes[8].

Additionally, it would be difficult for PAs to concisely and uniformly report on coordination with clean energy programs as each PA offers different programs, and "clean energy programs" are not clearly defined in the decision. The PAs, therefore, recommend removing these reporting requirements for inclusion on the DGStats

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[7] Resolution E-4999 at 63 (OP 1(f)).

[8] D.24-05-065 at 133 ("To be clear, Utilities and participating CCAs shall follow the auto-enrollment practice adopted by the Commission in D.20-07-008 and reiterated in Resolution E-5124.")

website at this time, and instead propose reporting the total number of low-income customers enrolled, where appropriate.

The proposed programmatic subscriber-related metrics for the GAP programs are summarized as the following:

1. Number of customers enrolled
2. Number of low-income customers enrolled
3. MWs Enrolled
4. Average customer monthly discount

Programmatic Information – Projects

The participating CCAs, the joint IOUs, and ED all agree that project level information is important to provide so that certain programmatic metrics can be displayed on the DGStats website. The project-specific related metrics that were discussed at the July Workshop per OP 6 of the Decision are “projects approved” and “projects completed.” Again, these would be reported in a summarized manner at the program-level.

It was also proposed that project facility status and location of project would be important fields to collect for help with displaying metrics by various segments. Additionally, the PAs propose providing the following fields to the vendor: 1) project name; and 2) technology type for each project.

The proposed project-related metrics for the GAP programs are summarized as the following:

1. Number of projects procured (“Projects approved” per D.24-05-065)
2. Number of projects online (“Projects completed” per D.24-05-065)

The proposed programmatic project-related fields for the GAP programs are summarized as the following:

1. Project name
2. Project facility status
3. Project capacity
4. Annual project generation
5. Project technology type
6. Project location (city, state, zip code)

Programmatic Information – RECs

The Decision eliminated the Green-e Certification process.[9] In lieu of Green-e Certification, the Decision requires that PAs conduct their own validation and tracking by including the following details in their modified program reporting after the retirement of Renewable Energy Certificates (RECs): megawatt-hours (MWh) of participant usage, MWh of Renewables Portfolio Standard (RPS) RECs retired for participants, and remaining MWh of usage to account for with program RECs.[10] The PAs understand this to mean that RECs retired for participants should be segmented into MWh of RPS RECs retired for participants from interim resources, and MWhs of RECs retired for program participants that are from dedicated programmatic resources. The "MWh of participant usage" should match the total number of MWh of total RECs retired for participants.

These data points are applicable to all programs, except the CRE Program, whose program design is still under consideration by the Commission.

The proposed programmatic REC-related metrics for the GAP programs are summarized as the following:

1. Annual MWh of participant usage
2. Annual MWh of RPS/interim RECs retired for participants
3. Annual MWh of programmatic/dedicated RECs retired for participants

Reporting Cadence

The PAs support reporting program metrics on a quarterly basis as required under OP 6 of the Decision. However, while most metrics can be reported on a quarterly basis, some of the above metrics, including those metrics that were not previously included in program reporting, need to be updated on an annual basis, such as annual program costs. Reporting certain metrics on an annual basis will ensure that PAs can provide the actual data rather than a forecast or estimate. Additionally, PAs retire RECs on an annual basis after participant usage and developer generation has been finalized for the prior calendar year, and therefore PAs propose that metrics related to MWhs of generation and usage (i.e., total MWhs of project generation, MWhs of participant usage, MWhs of dedicated and/or interim RECs retired for participants, and

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[9] *Id*. at 172 (OP 3(g)) ("Green-e certification is no longer required. Consistent with Ordering Paragraph 6 below, Quarterly reporting to California Distributed Generation Statistics (DGStats) website, or another website as determined by ED, shall include: megawatt-hours (MWh) of participant usage; MWh of Renewable Portfolio Standard (RPS) Renewable Energy Credits (RECs) retired for participants; and remaining MWh of usage to account for which program RECs.")

[10] *Id*.

unsubscribed MWhs) be made on an annual cadence as well, after RECs have been retired.

Lastly, the PAs propose that average monthly customer discount be calculated and reported on an annual basis once actuals from the year have been finalized, and that the average monthly discount be derived from discounts provided every month of the calendar year.

The proposed cadence for updating each reported metric is provided in more detail in Appendix A-1.

Interim Reporting

In the interim period prior to the implementation of reporting on the DGStats website, PAs will continue to file quarterly reports for the GAP programs.[11] This will ensure that program reporting continues without interruption and/or unnecessary confusion. There were two criteria that were established at the July 19 workshop that must be true to begin reporting on the DGStats website:

1. The GAP program in question must be fully designed and have data to provide and;
2. The DGStats website module for the GAP program in question must be live and fully operational.

Once these two requirements are met, the PAs will switch to reporting in the new system to ensure centralized reporting. The IOUs and Participating CCAs do not believe that it would be beneficial to transfer any historical reporting information into the DGStats website. This would be an unnecessary expense.

Efforts to Better Coordinate and Automate the Data Collection and Transfer Process

OP 8 directs the IOUs and participating CCAs to outline “any efforts planned to better coordinate amongst the various Program Administrators and to automate the data collection and transfer process.” First, addressing plans to better coordinate, the PAs agree that once a vendor is selected to update the DGStats website, a source of funding is determined, and the GAP programs are fully designed, the PAs for each program will meet to begin discussions with the vendor to initiate website development. The PAs anticipate there may be standing meetings to discuss scope of work, timing for both the buildout of the GAP website modules, and timing related to when the quarterly and annual data will be provided to the vendor and when the updates will be made to the website, etc. Once the website is established, the PAs may also benefit from hosting

[11] Per D.21-12-036, PG&E is required to file monthly progress reports for its GTSR program. As directed, PG&E will continue the monthly cadence unless a letter from the Executive Director of the Energy Division is received that adjusts the required cadence to quarterly.

optional meetings on a quarterly or semi-annual cadence (at least initially) to ensure that the website is functioning as expected, and to address any issues or discuss any areas for improvements.

Next, given the DGStats vendor for 2025 and beyond is still to be determined, the PAs agreed that it is too early to discuss any level of automation as it relates to the data collection and transfer process. Internal automation has a cost associated with it, and each PA's internal Information Technology systems will operate differently across the various programs. In some instances, and depending on the PA and program, the data collection process may be simple to automate. In other cases, manual reporting may be preferred to provide the data in the needed format for data transfer to the vendor.

Data transfer is different than data collection, and this difference is important when considering automation. Data collection refers to how each LSE collates the data internally, whereas data transfer relates to the process by which the LSE sends the data to the vendor for display on the website. If automation is desired, the automation of data transfer and associated cost and the funding source for this potential expense will need to be discussed upon selection of a vendor for the DGStats website. Building an Application Programming Interface (API) is one way to automate data transfer, though given the associated costs, it may be more beneficial to simply transfer files to the vendor "manually" using Secure File Transfer Protocol (SFTP) each quarter. Any level of automation is likely to substantially increase the funding required to report the metrics. Given the potentially large cost associated with any automation between multiple PAs and a chosen vendor, the PAs request that if this is needed, it be mandated by Commission direction and with an appropriate cost recovery mechanism.

Similarly, PAs request that a budget and funding source for the DGStats work be provided by the Commission. This could be in the form of a Resolution in the DGStats proceeding that would increase the funding for the DGStats website to account for GAP reporting needs and also order the incorporation of community solar statistics into the contract.[12] The PAs put forth this proposal as the most cost-effective and streamlined approach. The participating CCAs will need to determine if one PA should hold the master contract with the vendor for all participating CCAs.

PROGRAM REPORTING SPECIFICS

DAC-GT & CSGT PROGRAMS

Current Reporting Requirements

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[12] IOUs will establish a co-funding agreement ensuring ratepayer indifference between service territories.

The IOUs and the CCAs, as PAs, are subject to the same DAC-GT and CSGT reporting requirements. The PAs have been filing quarterly and semi-annual reports for the DAC-GT and CSGT programs pursuant to Resolution E-4999.

The current reporting requirements are as follows:

DAC-GT/CSGT Quarterly Reports:

- Capacity procured
- Capacity online
- Customers subscribed
- DAC census tract where project is located
- Number of participating customers in each DAC census tract
- Number of customers newly enrolled in CARE/FERA

CSGT Semi-Annual Reports:

- Number of income-qualified customers subscribed to each CSGT project
- Capacity allocated to subscribed customers
- Whether waitlist of non-qualified customers exists; size of waitlist
- Whether Project Sponsor is receiving bill credits from the Project
- Project sponsor's subscription size
- Number of master-metered accounts participating in CSGT
- Total program capacity allocated to master-metered accounts

Proposed Updated Reporting for DAC-GT/CSGT

In light of the Decision, the PAs recommend keeping the existing metrics above when transitioning to DGStats reporting with several exceptions below for the DAC-GT/CSGT programs.

Metrics to Discontinue

The PAs propose to discontinue reporting which DAC census tract the project is located in as the project siting requirements were expanded under the Decision.[13]

PAs currently report on the number of customers in each DAC census tract as part of the DAC-GT/CSGT quarterly reports. The PAs propose that this metric be discontinued

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[13] *See* D.24-05-065 at 170 (OP 3(a)) ("Site requirements are revised to allow eligible projects to be located no more than five miles from eligible disadvantaged communities census tracts.")

in order to streamline reporting as all customers, with the exception of CSGT sponsors, must be residents in a DAC.

The PAs propose to discontinue reporting on capacity allocated to subscribed customers and information on wait-lists of non-qualified customers (verification if a list exists and, if so, the size of each list) as part of the CSGT semi-annual reports. The metric regarding capacity allocated to subscribed customers should be discontinued as it provides redundant information to the program capacity metrics that will be reported in DGStats. The wait-list information should also be discontinued to streamline reporting of useful and timely information.

Proposed Updated CSGT Reporting

While the Decision discontinued future solicitations for the CSGT program, reporting for existing CSGT projects would continue. PAs that have already contracted for CSGT projects or have CSGT procurement in existing active solicitations at the time of issuance for the Decision and plan to continue their CSGT program will report on program metrics and fields in accordance with OP 6 of the Decision.[14]

The PAs propose that the CSGT program reporting in DGStats include all the same metrics and fields as DAC-GT. However, since the CSGT Program has additional requirements and provisions (e.g., Project Sponsors) beyond the modified DAC-GT program, CSGT PAs should report on additional CSGT project and program specific data beyond that reported for DAC-GT. The PAs propose CSGT PAs report on two additional metrics and six additional fields: two regarding programmatic information (reflected in both metrics and fields) and four fields regarding project information.

The PAs also proposes one modification to CSGT reporting not discussed below. The Program—Subscriber metric category should not include Project Sponsor data in the "average customer monthly discount" metric.[15] Other reporting proposals regarding Project Sponsors are addressed below.

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[14] PAs who will no longer offer the CSGT program, will no longer report on CSGT following the full transition of their CSGT program to the modified DAC-GT.

[15] With respect to calculating an average customer monthly discount for CSGT Reporting, CSGT PAs should not include a Project Sponsor's bill discount (if the Project Sponsor elects to receive one) as a Project Sponsor is eligible to receive up to 25 percent of a CSGT project's output (according to Resolution E-4999, Findings and Conclusions 24). A Project Sponsor's subscription size (and bill discount - if the Project Sponsor elects to receive one) could be significantly larger than residential CSGT subscribers and could skew average bill discount data.

Additional Programmatic Information

PAs operating a CSGT program will report on two additional program metrics that will also be reflected as two additional program fields: the number of master-metered accounts participating in the CSGT program and the total CSGT capacity allocated to those master-metered accounts under the Program-Subscriber field category. The PAs propose reporting on two CSGT-specific program metrics relative to master-metered accounts to better capture all potential CSGT subscribers in DGStats: the number of master-metered accounts participating in the CSGT program, and the total program capacity allocated to those master-metered accounts.

Additional Project Information

PAs operating a CSGT program will report on four additional project fields, two under the Project-Community field category and two under the Project-Subscriber field category. CSGT PAs will report on job training, and local hiring under the Project Community category. Those fields will include the number of workers registered in a State of California approved apprenticeship program and the number of workers whose place of residence is located within a 25- mile radius of the CSGT project, respectively. This information is project-specific and improves visibility into project information if displayed at the project-level.

Under the Project-Subscriber field category, CSGT PAs will report if a Project Sponsor is receiving energy and, if so, the Project Sponsor's subscription size. This information is also project-specific and provides greater visibility into project information if displayed at the project-level.

PAs operating a CSGT program will continue to provide information on the number of income-qualified customers subscribed to each CSGT project.

Modified Green Tariff & ECR Programs

The Decision modified the Green Tariff option and closed the ECR option to all new procurement not currently under negotiation or contract. SCE is the only utility with dedicated ECR projects that is either online, approved or under negotiation.

Current Reporting Requirements

Decision 15-01-051 directed the participating IOUs to submit monthly GTSR program progress reports as well as an annual program progress report. In Resolution E-5028,[16] the Commission streamlined and consolidated GTSR reporting requirements. Specifically, the Commission modified the frequency of its GTSR program reports from monthly to quarterly.[17]

The current reporting requirements are as follows:

Quarterly GTSR Program Progress Reports[18]:

- "Available capacity" data at the most detailed level feasible, updated monthly, and work to increase the precision of the information over time.
- Summary of monthly advisory group activities, or consultation with Community Based Organizations (CBOs), if any.
- ECR Contract Report
- Attach Generation Transfer Report (Reported in Quarter 3)

Annual GTSR Program Progress Reports:

- Enrollment Reporting, including "available capacity" data at the most detailed level feasible.
- One page summary tracking the amount and cost of generation transferred between the RPS and GTSR Program.
- GTSR Revenue and Cost Reporting summary.
- Summary of advisory group or advising network activities, including information regarding frequency of meetings, topics discussed, and any other relevant information.
- CCA Code of Conduct report. If applicable, summarize any marketing or lobbying efforts that are, or could reasonably be interpreted to be, subject to the CCA Code of Conduct.
- Supplier diversity.

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[16] Ordering Paragraph 6. The specific reporting requirement changes are described in detail in Attachment C of PG&E Advice Letter 3920-G/5206-E.

[17] Per D. 21-12-036, this reduced schedule was rescinded for PG&E only, with additional reporting requirements added; the Executive Director, or designee can inform PG&E when it may revert back to quarterly reporting.

[18] Per D. 21-12-036, this reduced schedule was rescinded for PG&E only, with additional reporting requirements added; the Executive Director, or designee can inform PG&E when it may revert back to quarterly reporting.

- Summary of CARE enrollment figures including location; location of CARE customers in relation to areas eligible for Environmental Justice ("EJ") Projects and in relation to planned or existing EJ Projects.
- Reports of fraud or misleading ads
- Enrollment figures for low-income customers and subscribers who speak a language other than English at home
- GTSR 20-year forecast[19]

Inclusion of ECR in DGStats Reporting

As discussed at the July 19 Workshop, despite the closure of the GTSR-ECR to new procurement, SCE will continue reporting program metrics under OP 6 referenced in Appendix A-1 under the ECR program column for projects that are currently online and those that will come online in the future, in line with its current process until DGStats is implemented. This approach ensures a uniform and dependable method across all programs.

Metrics to Discontinue

The PAs propose that both supplier diversity and summary of CARE enrollment figures be discontinued from the annual report. The PAs' current and potential contracts with GT and ECR partners have not counted toward supplier diversity goals, and therefore this metric is not applicable to the programs. Additionally, the CARE customer enrollment metric was created before the existence of DAC-GT/CSGT. Given the modified GT program is focused on providing a 100% renewable energy product for the general market population, the PAs recommend removing the low-income enrollment metric and the number of subscribers who speak a language other than English at home. The measure of program enrollment in these populations is not relevant and is not a measure of success for the modified GT or ECR programs.

The monthly advisory group activities are not included as a "metric" or evaluated for purposes of this advice letter as they are being evaluated as part of A. 22-05-022. They are listed here only for completeness and will not be included as a metric in DGStats.

Additionally, job training and workforce development tracking, although mentioned in the Decision, were never a goal nor a requirement for the GT and ECR Programs. Inclusion of these metrics is therefore unnecessary.

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[19] The GTSR 20-year forecast is not included as a "metric" or evaluated for purposes of this Advice Letter. It is listed here only for completeness.

Last, as the average customer monthly discount is not applicable to the modified GT or ECR programs, the PAs do not intend to display that information on the website.

Community Renewable Energy (CRE) Program

The Decision adopted the foundational elements of a new Community Renewable Energy Program. In June 2024, the Administrative Law Judge issued a ruling seeking additional party comments on programmatic details regarding the implementation of the CRE Program. Parties responded to questions in July of 2024. During the July 19 workshop, participating parties acknowledged that the parameters of the CRE Program are still under development in the proceeding, (A. 22-05-022, and related matters), and should not be discussed outside of vague generalities until program details are finalized.

Nonetheless, the group agreed that the number of MWs procured and participation levels in the CRE Program (by relevant segments) would be important metrics to establish once the program is created. Once a decision that further defines the CRE Program is adopted, the parties will be able to reconvene and discuss appropriate metrics for the program in more detail. Open dialogue between the IOUs, the participating CCAs, and ED will be important to ensure the chosen metrics measure important program objectives. The IOUs and CCAs acknowledged that an additional advice letter can be submitted at a later date to propose CRE Program metrics for incorporation onto the DGStats website.

TIER DESIGNATION

In accordance with OP 8 of this Decision, this advice letter is submitted with a Tier 1 designation.

EFFECTIVE DATE

This advice letter will become effective August 29, 2024, the same date submitted.

NOTICE

Anyone wishing to protest this advice letter may do so only electronically. Protests must be received no later than 20 days after the date of this advice letter. Protests should be submitted to the CPUC Energy Division at:

E-mail: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter should also be sent electronically to the attention of:

For SCE:

Connor Flanigan

Managing Director, State Regulatory Operations
Southern California Edison Company
E-mail: AdviceTariffManager@sce.com

and

Adam Smith
Director, Regulatory Relations
c/o Karyn Gansecki
Southern California Edison Company
E-mail: Karyn.Gansecki@sce.com

For PG&E:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
E-mail: PGETariffs@pge.com

For SDG&E:

Attn: Greg Anderson
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For Joint CCAs:

Attn: Brittany Iles
Counsel for Joint CCAs
E-mail: Iles@braunlegal.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this advice filing to the interested parties shown on SCE's GO 96-B and A.22-05-024 et. al. service lists. Address change requests to SCE's GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-6838. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

To view other SCE advice letters filed with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Joe Cox at (626) 302-4811 or by electronic mail at Joe.Cox@sce.com

Southern California Edison Company

/s/ Connor Flanigan
Connor Flanigan

CF:jc:bvs
Enclosure

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 79-E

Tier Designation: 2

Subject of AL: 2025 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing): COMPLIANCE

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-05-065, E-4999, E-5125,

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 8/8/24

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Amulya Yerrapotu
Title: Policy Analyst
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: (925) 378-6729
Facsimile (xxx) xxx-xxxx:
Email: ayerrapotu@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

APPENDIX A

Contact advicetariffmanager@sce.com for the excel sheet

SEPTEMBER FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

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September 3, 2024

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SUMMARY OF RECOMMENDATIONS

The California Community Choice Association recommends that the California Public Utilities Commission (Commission):

- Reject San Diego Gas and Electric Company's (SDG&E's) request that the Commission explicitly authorize Southern California Edison's (SCE's) "zig zag" methodology as a "middle ground" between the proportional allocation method and the waterfall method, because the zig zag method applied in practice is not proportional;

- Reject as baseless Pacific Gas and Electric Company's (PG&E's) assertion of Commission error for failure to consider the record on various issues including that the waterfall inappropriately shifts financial risk to the community choice aggregators and that the waterfall treats bundled and unbundled customers inequitably;

- Reject PG&E's and SDG&E's requests to establish a sunset date for the proportional allocation method, instead of the Proposed Decision's order that the proportional allocation method will apply "unless and until the Commission determines otherwise"; and

- Reject SDG&E's request for "flexibility" to mutually alter the payment allocation methodology through a joint advice letter with local community choice aggregators.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[1] to party opening comments on the proposed *Decision Extending Current Proportional Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*[2] (Proposed Decision), dated August 8, 2024.

I. INTRODUCTION

As noted in CalCCA's Opening Comments, the Proposed Decision adopting the proportional allocation method for partial past due payments should be adopted. CalCCA addresses below the Opening Comments of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E). Specifically, CalCCA recommends that the Commission:

- Reject SDG&E's request that the Commission explicitly authorize Southern California Edison's (SCE's) "zig zag" methodology as a "middle ground" between the proportional allocation method and the waterfall method, because the zig zag method applied in practice is not proportional;

- Reject as baseless PG&E's assertion of Commission error for failure to consider the record on various issues including that the waterfall inappropriately shifts financial risk to the community choice aggregators (CCA), and that the waterfall treats bundled and unbundled customers inequitably;

- Reject PG&E's and SDG&E's requests to establish a sunset date for the proportional allocation method, instead of the Proposed Decision's order that the proportional allocation method will apply "unless and until the Commission determines otherwise"; and

- Reject SDG&E's request for "flexibility" to mutually alter the payment allocation methodology through a joint advice letter with local CCAs.

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[1] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[2] Proposed *Decision Extending Current Proportional Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*, Rulemaking (R.) 18-07-005 (Aug. 8, 2024).

II. SDG&E'S REQUEST FOR SCE'S ZIG ZAG TO BE AUTHORIZED IN PLACE OF PROPORTIONAL ALLOCATION SHOULD BE REJECTED

The Commission should reject SDG&E's request to authorize the use of the "zig zag" payment methodology instead of the proportional allocation method. The "zig zag," previously used by SCE[3] and authorized only for the term of the waterfall suspension in D.21-11-014,[4] has turned out not to be a "variation" of the proportional allocation method as SDG&E describes.[5] Instead, SCE's application of the zig zag in practice has resulted in a form of the waterfall. SCE has previously described the zig zag as creating "a payment posting priority that alternates payments between the investor-owned utility (IOU) and the CCA starting with the oldest arrearages a customer has."[6] On paper, the "alternating" of payments appears to result in proportional payments over a period of time. In practice, however, SCE has devised a system in which its charges, within a billing cycle, are always older than the CCA charges, resulting in SCE always getting paid first. As described below, the zig zag in practice (1) is not proportional, (2) has a material negative impact on CCA financial stability, and (3) is overly complex from an operational standpoint. The Commission should reject SDG&E's request to explicitly authorize the zig zag method in place of the proportional allocation method.

A. The Zig Zag Method in Practice Creates a Masked "Waterfall" to the IOUs and Should Not Be Allowed

SDG&E likely favors SCE's zig zag because in practice it is not a proportional allocation methodology but rather results in a masked waterfall. Currently in SCE's territory, if a customer continually makes on-time and complete payments, the zig zag approach is proportional because both SCE's and the CCA's charges are paid off in full. However, when customers are behind on their bills, make partial payments, or receive bills with multiple charges (due to delayed billing), the zig zag approach favors SCE as the funds are not distributed equally between SCE and the CCA. In these scenarios, the SCE charges are paid off first because SCE views these charges as older than the CCA charges. The reason SCE views their charges (for the same bill period) as being older than the CCA charges is because SCE reads the meter and is able to calculate the customer's charges within

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[3] SCE did not file comments on the Proposed Decision, and therefore appears to support the Proposed Decision's requirement that the IOUs use the proportional allocation method, instead of the zig zag or waterfall methods.

[4] D.21-11-014, *Decision Directing Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators*, R.21-02-014 (Nov. 18, 2021).

[5] SDG&E Opening Comments, at 1.

[6] *See Southern California Edison Company's (U 338-E) Brief on Ruling Setting Joint Status Conference and Ordering Comments,* R.17-06-024, R.21-02-014 (Aug. 27, 2021), at 3 (describing the zig zag method).

approximately one day, but the CCA must receive the usage from SCE before it can calculate the CCA charges and send them back to SCE to be presented on a bill. Because of the additional approximately two days for the CCA to receive the usage from SCE and return the CCA charges to SCE, SCE deems its charges as older and deprioritizes CCA charges for the same bill period.

SDG&E's Appendix A provides an example of the zig zag that is not how the zig zag is currently applied in SCE's territory. First, in any billing cycle, SDG&E assumes that the IOU charges and CCA charges are of the same age. However, in practice, the IOU calculates its portion of the bill first and then receives the CCA charges a day or more later. While the charges are on the same bill, for purposes of calculating which arrearage is paid first, the IOU's charges are always the oldest. Second, SDG&E conveniently assumes that each arrearage payment is exactly fifty percent of the bill amount. This means that for every other payment, the IOU and CCA will have collected one full past due bill. This means that the percent of arrearage outstanding will align every other month.

In Appendix A attached hereto, CalCCA provides an example of how the zig zag actually works in SCE's territory. Charges from the IOU are older than that of the CCA in each bill, and as is typical the amount paid is not exactly half of each past due bill. The result is that the amount in arrears after the first payment always demonstrates the IOU is paid first resulting in a lower percentage of arrears for the IOU. For comparison, Appendix A also includes the amounts paid to each entity when the true proportional allocation method is used. The comparison demonstrates that the zig zag is not analogous to the proportional allocation method, and should be rejected.

B. The Zig Zag Should be Rejected as it Has a Material Negative Impact on CCAs and is Operationally Complex to Implement and Manage

The zig zag method should be rejected given its material negative impact on CCAs. The zig zag is also overly complex to implement and manage from an operations standpoint. Given the magnitude of arrearages currently, both the IOUs and CCAs are anxious to receive even partial past due payments from customers in arrears. Compounding the arrearages are complexities in billing that have resulted recently in a large number of bills, especially in SCE's territory, being delayed. The result is that customers receive large bills with amounts due from previous billing periods, which if paid only partially fall into the zig zag payment methodology. The zig zag in practice, like the waterfall as recognized in the Proposed Decision, "inappropriately shifts financial risk to the CCAs" and is not in the public interest given it prioritizes paying the IOUs first. In addition, as demonstrated in Appendix A, the zig zag is overly complex and difficult to manage from an operational standpoint, and is confusing to customers.

The Commission should reject SDG&E's request to explicitly authorize SCE's zig zag given that in practice it results in a masked waterfall, and does not result in proportional allocation of partial past due payments between the IOUs and CCAs.

III. PG&E'S ASSERTION OF COMMISSION ERROR FOR FAILURE TO CONSIDER THE RECORD ON VARIOUS ISSUES IS BASELESS AND SHOULD BE REJECTED

PG&E's assertions of Commission error for failure to consider the record on various arguments advanced by PG&E, SDG&E, and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) are baseless and should be rejected. Specifically, PG&E states that the Proposed Decision fails to consider arguments by PG&E, SDG&E, and Cal Advocates before concluding that (1) the waterfall method inappropriately shifts financial risk to the CCAs, and (2) the proportional allocation method results in more equitable treatment of bundled and unbundled customers.[7] The Proposed Decision, however, spends nearly three pages summarizing party arguments. The Proposed Decision also incorporates analysis from D.21-11-014 supporting temporarily suspending the waterfall method during the COVID pandemic on these exact topics, and then provides additional analysis supporting its conclusions.[8] Given the Proposed Decision's more than adequate analysis on these issues, PG&E's assertions of error are simply a cover for its disagreement with the Commission's conclusions, and should be rejected.

IV. PG&E'S AND SDG&E'S REQUESTS FOR THE PROPOSED DECISION TO SPECIFY A SUNSET DATE FOR THE PROPORTIONAL ALLOCATION METHOD SHOULD BE REJECTED

PG&E's and SDG&E's request for a sunset to the proportional allocation, instead of the Proposed Decision's conclusion that the proportional allocation method be applied "unless and until the Commission determines otherwise," should be rejected. Both PG&E and SDG&E claim that the Commission's temporary allowance of the proportional allocation method in D.21-11-014 provides support for again establishing a sunset date. However, PG&E and SDG&E fail to note that the sunset established in D.21-11-014 was because the decision was issued in the COVID Proceeding, R.21-02-014, as a part of relief programs established to assist customers during the pandemic. It therefore made sense to align the timeframe for the proportional allocation with other relief programs,

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[7] PG&E Opening Comments, at 2-3.

[8] *See* Proposed Decision, at 4-5 (allocation of risk between CCAs and customers), and 5-6 (equitable treatment of bundled and unbundled customers).

including the COVID-19 Payment Plans.[9] Here, the Commission is finally addressing the need to indefinitely extend the proportional allocation method, without facing the unique circumstances to align the temporary relief provided in the COVID proceeding.[10] The Proposed Decision's finding that the proportional allocation method should continue until the Commission determines otherwise should therefore remain unchanged.

V. SDG&E'S REQUEST FOR "FLEXIBILITY" TO MUTUALLY ALTER THE PAYMENT ALLOCATION METHODOLOGY THROUGH A JOINT ADVICE LETTER WITH LOCAL CCAS SHOULD BE REJECTED

SDG&E's request for "flexibility" to "negotiate the method of payment allocation that is best for customers and CCAs alike in the local service territory at some point in the future" and to allow updates to that payment allocation through a Tier 2 advice letter, should be rejected.[11] Aside from the fact that CCAs in SDG&E's service territory support the indefinite application of the proportional allocation method for all of the reasons advanced in the Proposed Decision, SDG&E's request to relax the Commission's directives once the Proposed Decision is adopted should be rejected. SDG&E should not be allowed to file a Tier 2 advice letter, whether "joint" or not, to gain "flexibility" with respect to that method.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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

September 3, 2024

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[9] *See* D.21-11-014, at 1-2 ("During the pandemic, the Commission and Legislature directed electric utilities to suspend their standard practice of prioritizing payments first for the utility charges. Today's decision extends the same direction to encompass all payments on outstanding bills through September 2024, the period equivalent to the duration of the COVID-19 Payment Plans.").

[10] PG&E Opening Comments, at 4; SDG&E Opening Comments, at 2-3.

[11] *See* SDG&E Opening Comments, at 3.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION EXTENDING CURRENT PROPORTIONAL ALLOCATION OF PAYMENT ON PAST-DUE BILLS BETWEEN INVESTOR-OWNED UTILITIES AND COMMUNITY CHOICE AGGREGATORS

		Zig Zag Oldest charges are prioritized		Applied to Bill		Proportional Percent Payments are applied proportionally	
	Total	IOU Balance	CCA Balance	IOU	CCA	IOU Balance	CCA Balance
Bill 1 (IOU Charges Calculated First)	150	100				100	
Bill 1 (CCA Charges calculated second)			50				50
Bill 2 (IOU Charges Calculated First)	150	100				100	
Bill 2 (CCA Charges calculated second)			50				50
Bill 3 (IOU Charges Calculated First)	150	100				100	
Bill 3 (CCA Charges calculated second)			50				50
Beginning Balance	450	300	150			300	150
Percent of Bal.	100%	67%	33%			67%	33%
Payment 1	-80	-80	0	Bill 1 - $80		-53	-27
Balance	370	220	150			247	123
Percent of Bal.	100%	59%	41%			67%	33%
Payment 2	-80	-30	-50	Bill 1 - $20, Bill 2 - $10	Bill 1 - $50	-53	-27
Balance	290	190	100			193	97
Percent of Bal.	100%	66%	34%			67%	33%
Payment 3	-80	-80	0	Bill 2 - $80		-53	-27
Balance	210	110	100			140	70
Percent of Bal.	100%	52%	48%			67%	33%
Payment 4	-80	-30	-50	Bill 2 - $10, Bill 3 - $20	Bill 2 - $50	-53	-27
Balance	130	80	50			87	43
Percent of Bal.	100%	62%	38%			67%	33%
Payment 5	-80	-80	0	Bill 3 - $80		-53	-27
Balance	50	0	50			33	17
Percent of Bal.	100%	0%	100%			67%	33%
Payment 6	-50	0	-50		Bill 3 - $50	-33	-17
Ending Balance	0	0	0			0	0

FILED
09/04/24
04:59 PM
R2401018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ESTABLISHING TARGET ENERGIZATION TIME PERIODS AND PROCEDURE FOR CUSTOMERS TO REPORT ENERGIZATION DELAYS

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September 4, 2024

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V. CONCLUSION.....5

SUMMARY OF RECOMMENDATIONS

The California Community Choice Association recommends that the California Public Utilities Commission:

- Reject Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's (collectively, the IOUs) requests to lengthen energization targets and timelines in multiple scenarios;
- Reject the IOUs' recommendations to increase reporting frequency and narrow data reporting requirements; and
- Adopt Silicon Valley Clean Energy's request to apply the final Decision to existing projects and reject the IOUs' requests to delay the final Decision's effective date.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ESTABLISHING TARGET ENERGIZATION TIME PERIODS AND PROCEDURE FOR CUSTOMERS TO REPORT ENERGIZATION DELAYS

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[1] to party opening comments on the proposed *Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays*[2] (Proposed Decision), dated August 12, 2024.

I. INTRODUCTION

Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE), and San Diego Gas & Electric Company's (SDG&E) (collectively, the IOUs) Opening Comments center around three requests: (1) lengthen the energization targets and timelines; (2) reduce the frequency of reporting and narrow the breadth of data required in the reporting; and (3) delay the effective date of the Proposed Decision's energization requirements. The IOUs' recommendations are in stark contrast to the requirements of AB 50[3] and SB 410[4], as well as recommendations of stakeholders in Opening Comments, to shorten energization targets and timelines and increase IOU energization responsibilities. The IOUs' recommendations represent a "business as usual" approach that ignore the severe energization backlog threatening the state's electrification and decarbonization goals.

The Legislature addressed the growing outcry of severely backlogged energization projects in SB 410 and AB 50, answering the urgent need to promptly energize customer facilities to support the state's decarbonization goals. To serve the rapidly increasing load of electrified buildings and vehicles, the California Energy Commission forecasts a need for nearly 180 gigawatts of new generating capacity by 2040 to meet SB 100[5] policy goals.[6] The development of these new generating resources

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[1] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[2] Proposed *Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays*, Rulemaking (R.) 24-01-018 (Aug. 12, 2024).

[3] Assembly Bill 50 (Stats. 2023, ch. 317) (AB 50).

[4] Senate Bill 410 (Stats. 2023, ch. 394) (SB 410).

[5] Senate Bill 100 (Stats. 2018, ch. 312) (SB 100).

[6] 2021 SB 100 Joint Agencies report, Figure 9 at 15: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

will come with significant costs. If the build-out of this new capacity outpaces the ability to energize new load, rates may increase and reaching the SB 100 goals will be at risk.

CalCCA supports the Proposed Decision, which sets a measured path toward requiring the IOUs to meet initial energization targets and timelines. At the same time, the Commission can collect data from the IOUs to uncover the root causes of the delays to refine the energization requirements in Phase 2. In response to Opening Comments, CalCCA recommends that the Commission:

- Reject the IOUs' requests to lengthen energization targets and timelines in multiple scenarios;
- Reject the IOUs' recommendations to increase reporting frequency and narrow data reporting requirements; and
- Adopt Silicon Valley Clean Energy's (SVCE) request to apply the final Decision to existing projects and reject the IOUs' requests to delay the final Decision's effective date.

II. THE IOUS' REQUESTS TO LENGTHEN ENERGIZATION TARGETS AND TIMELINES IN MULTIPLE SCENARIOS SHOULD BE REJECTED

IOU recommendations to lengthen energization targets and timelines for various scenarios ignore the current energization delays that sparked AB 50 and SB 410, and should be rejected. PG&E, SCE, and SDG&E each argue for increased timelines,[7] while many stakeholders go the opposite direction and recommend that the Proposed Decision be modified to shorten the targets and timelines.[8] CalCCA agrees with the middle ground approach in the Proposed Decision to moderately reduce the compliance targets and timelines in Phase 1, without penalties at this point for the IOUs' failure to comply. The Phase 1 targets and timelines, coupled with the expeditious collection of robust data, can adequately inform refinement of the targets and timelines in Phase 2. Unfortunately, instead of diving in to remedy the energization emergency through their best efforts in Phase 1, the IOUs remain singularly focused on their perceived inability to meet the proposed targets and timelines. If the Phase 1 data demonstrates that the IOUs are correct that any of the scenarios they have raised should be carved out of the target or timeline because they are indeed outside of IOU control, the Commission can do that in Phase 2 after analyzing the data with stakeholder input. The Proposed Decision strikes a balance for Phase 1 between establishing initial targets and timelines without penalizing the IOUs for

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[7] PG&E Opening Comments, at 1-3, 6-8; SCE Opening Comments, at 2-6; SDG&E Opening Comments, at 8-14.

[8] Advanced Energy United Opening Comments, at 1-3; CALSTART Opening Comments, at 2-5, 10-13; Interstate Renewable Energy Council Opening Comments, at 1-6, 8-12; Powering America's Commercial Transportation Opening Comments, at 4.

failure to comply. The IOUs' requests to lengthen energization targets and timelines are therefore unnecessary and should be rejected.

III. THE IOUS' REQUESTS TO SUBMIT DATA ANNUALLY RATHER THAN BIANNUALLY AND TO NARROW THE DATA REQUESTS SHOULD BE REJECTED

IOU recommendations to change the Proposed Decision's data reporting frequency and narrow the categories of data to be collected should be rejected. PG&E, SCE, and SDG&E all recommend annual, rather than biannual, reporting, arguing that increased reporting frequency is burdensome, excessive, costly, and not required by either AB 50 or SB 410.[9] They further recommend limiting the magnitude of data to be collected, stating they lack the ability to collect much of the data listed in Appendix B of the Proposed Decision, and that doing so will divert resources from energizing customers.[10]

First, the IOUs recommend modifying the biannual reporting frequency to annually. While annual reporting may become sufficient after the Commission establishes its refined energization targets in Phase 2, more frequent reporting is necessary immediately to inform Phase 2. In fact, the Phase 2 schedule has party opening briefs on Phase 2 issues due in March 2025, and a Phase 2 Decision is scheduled to be issued in the third quarter of 2025.[11] Without quarterly reporting as CalCCA recommends in Opening Comments,[12] data will not be available in time to inform the Phase 2 proceedings. The Commission should therefore reject the IOUs' requests and require the IOUs to report quarterly on the Appendix B data.

Second, the IOUs' requests to narrow the data required by Appendix B should be rejected. Information from the Appendix B reporting is necessary to accurately refine the targets and timelines in Phase 2. As noted in the Proposed Decision, the data provided by the IOUs in response to the ALJ Rulings was incomplete, and uncovered the need for increased reporting and monitoring to accurately set the targets:

> We find that the information provided by the large electric IOUs to date is <u>inadequate to support full implementation of Pub. Util. Code § 933.5(a)(2)(B)</u>. While the large electric IOUs collected some of the data necessary to evaluate timeliness of customer energization

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9 PG&E Opening Comments, at 5; SCE Opening Comments, at 8; SDG&E Opening Comments, at 2.

10 PG&E Opening Comments, at 5; SCE Opening Comments, at 8; and SDG&E Opening Comments, at 1.

11 *Assigned Commissioner's Scoping Memo and Ruling,* R.24-01-018 (Mar. 28, 2024), at 9.

12 *See* CalCCA Opening Comments, at 10.

> requests, there are many gaps that must be addressed to ensure statutory compliance.[13]

The IOUs cite the costs, staffing, and effort required to answer the data requests.[14] SDG&E even tries to entice the Commission to accept a "benefit" of narrowing the Appendix B requirements to "reduce[] the amount of data [for Energy Division staff] to analyze, thereby reducing workload and associated costs."[15] SDG&E misses the mark and its (and the other IOUs') recommendations are the exact opposite of what is needed – accurate, robust data to uncover the root causes of the extreme energization delays and to set accurate and accelerated targets.

The IOUs' requests to set annual and narrowed requirements for IOU reporting should be rejected. Instead, the Commission should adopt CalCCA's request for Appendix B quarterly reporting.[16]

IV. THE COMMISSION SHOULD ADOPT SVCE'S REQUEST THAT THE FINAL DECISION APPLY TO EXISTING ENERGIZATION PROJECTS AND REJECT THE IOUS' REQUESTS TO DELAY THE FINAL DECISION'S EFFECTIVE DATE

The Commission should adopt SVCE's recommendation to apply the final Decision's requirements to existing projects that began the energization process before the targets were adopted.[17] SVCE's recommendation makes sense, to ensure pending energization projects benefit from the new targets and timelines and to obtain data regarding those projects. CalCCA provides similar requests for energization data for all pending energization projects in its Opening Comments.[18]

The Commission should also reject the IOUs' recommendations to delay the effective date of the final Decision's requirements, which will delay obtaining data on the root causes of the energization backlog and worsen the energization crisis. The IOUs' recommendations include delaying the customer engagement requirements to allow additional time to develop processes and train staff.[19] SDG&E, seemingly ignoring the emergency energization delay situation, calls the Proposed Decision's requirement for the targets to take effect immediately "flawed," stating that

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13 Proposed Decision, at 47 (emphasis added).

14 PG&E Opening Comments, at 5; SCE Opening Comments, at 7-8; SDG&E Opening Comments, at 1-3.

15 SDG&E Opening Comments, at 3.

16 *See* CalCCA Opening Comments, at 10.

17 *See* SVCE Opening Comments, at 7 ("The Proposed Decision does not explain [its requirements'] applicability to projects that may have already initiated contact with the IOU or gone through several steps in the energization process. The applicability to this type of project should be retroactive, meaning that a project that began the energization process before the targets were adopted but has not been energized for longer than the applicable maximum energization timeline would indicate lack of compliance by the IOUs.").

18 *See* CalCCA Opening Comments, at 5-8.

19 PG&E Opening Comments, at 3.

"from a legal perspective, nothing in SB 410 mandates an immediate or hasty implementation of the energization targets or reporting requirements."[20] Therefore, SDG&E appears to believe that mere implementation of the target energization time periods required by SB 410 by September 30, 2024, is sufficient from a "legal perspective." The legislative history of SB 410 and AB 50 belie SDG&E's interpretation of the urgency:

> [D]elays for connecting electric vehicle fast chargers were around 70 weeks in PG&E territory in 2022. The slow connection of critical climate appliances and resources could inhibit California's targets to decarbonize buildings and clean the grid. This legislation requires the PUC to improve existing delays in interconnections, as well as plan for future ones.[21]

The legislative history also states:

> Severe electric interconnectivity delays have become the everyday reality of utility customers in California. In just one county located in [the bill author's] district, over 30 customers were told they would have to wait over 10 years for their lights to be turned on. This is unacceptable and alarming here in California, where we have set some of the most ambitious climate goals in the world. Currently, families and business-owners are being asked pay significant planning fees – up to hundreds of thousands of dollars – upon receiving "Will Serve" letters provided by utilities. As it turns out, "Will Serve" really means "Will Serve Eventually." As we strive to advance housing development, expand business, and meet our climate change goals, we have to get serious about the realities of electrification.[22]

The Proposed Decision correctly captures the legislative intent, stating "it is imperative that utilities begin planning and aiming to achieve these targets now."[23] The Commission should reject the IOUs' recommendations to delay the effective date for implementation of the energization requirements.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

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[20] SDG&E Opening Comments, at 4.

[21] *California Senate Committee on Energy, Utilities and Communications,* SB 410 (Mar. 13, 2023), at 8.

[22] *California Assembly Utilities and Energy Committee, Assembly Appropriations Committee, AB 50 (Wood) Assembly Third Reading, as amended* (May 18, 2023), at 2.

[23] Proposed Decision, at 62 (emphasis added).

Respectfully submitted,

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