APRIL FILINGS

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

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 Through December 31, 2024. (U 39 E)	Application No. 25-02-013

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

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April 4, 2025

SUMMARY OF RECOMMENDATIONS

- The Commission[1] should set this matter for hearing to fully examine the issues raised by PG&E's Application and other issues that may arise during the course of this proceeding.

- The Commission should modify PG&E's proposed list of scoping issues to expressly indicate a thorough review of PG&E's attempts to sell excess RA consistent with its Bundled Procurement Plan in 2024 is in scope in this proceeding. Specifically, the Commission should modify PG&E's proposed list of scoping issues as follows:

> 5. Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan<u>, including whether PG&E made reasonable attempts to sell excess RA consistent with its Bundled Procurement Plan</u>

- The Commission should adopt CalCCA's proposed procedural schedule.

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

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

The California Community Choice Association[2] (CalCCA) hereby protests the relief sought in the above-captioned ***! ""#$%&'$( ) *(+*, &%$#%*- & *&) / *0 #1%2$%*3 (4 "&) 5*6, - 7 0 8*+(2* 3 (4 "#$&) %1*9 1: $1; *(+*< '$$5*= ;) 1/ *- 1) 12&'$( ) *= "12&'$( ) . >*, (2'+(#$(*! #(%&'$( ) *? &#&) %$) @* ! %%(A) '*0) '2$1. >*0) 12@5*9 1. (A2%1*9 1%(: 125*! %%(A) '*0) '2$1. >*3 ( ) '2&%*! / 4 $) $ '2&'$( ) >*0 %( ) (4 $%* B$ "&'%C*(+*0 #1%2$%*9 1. (A2%1. >*< '$$5*= ;) 1/ * 1) 12&'$( ) *DA1#*; 2(%A214 1) '>*&) / *= 'C12*! %$ $$1. * +(2*C1*9 1%(2/ *; 12$(/ *E&) A&25*F*GC2(A@C*B 1%14 H12*1 F>*JKJL*6< *1 M0 8**** (Application) pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission.

In its Application, PG&E requests the California Public Utilities Commission (Commission) find:

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

1. That it prudently administered and managed its utility-owned generation (UOG) facilities in compliance with all applicable rules, regulations, and Commission decisions;

2. That it achieved least-cost dispatch of its energy resources and economically-triggered demand response programs pursuant to Standard of Conduct No. 4 (SOC 4);

3. That the entries recorded in the Energy Resource Recovery Account (ERRA) and the Portfolio Allocation Balancing Account (PABA) are reasonable, appropriate, accurate and in compliance with Commission decisions;

4. That its fuel procurement and hedging activities complied with its 2014 Bundled Procurement Plan (BPP);

5. That its Greenhouse Gas Compliance Instrument Procurement complied with the 2014 BPP;

6. That its resource adequacy (RA) sales complied with the Bundled Procurement Plan (BPP);

7. That the costs incurred and recorded in the Green Tariff Shared Renewables Memorandum Account (GTSRMA), Green Tariff Shared Renewables Balancing Account (GTSRBA), Disadvantaged Communities – Single-Family Solar Homes (DAC-SASH) balancing account (DACSASHBA), Disadvantaged Communities Green Tariff Balancing Account (DACGTBA), Community Solar Green Tariff Balancing Account (CSGTBA), and Centralized Local Procurement Sub-Account (CLPSA) in the New System Generation Balancing Account (NSGBA) are reasonable and in compliance with applicable tariffs and Commission directives; and

8. That the contract amendments related to the Alpine Solar, Agua Caliente Solar, and Daggett 2 BESS projects, and the Poblano Energy Storage Project, are reasonable and approved.[3]

The impact of PG&E's Application on both departed and bundled customers requires careful consideration under the applicable standards of review. In ERRA Compliance proceedings, PG&E, as the applicant, has the burden of proof[4] and must satisfy that burden based on a preponderance of the evidence.[5]

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3 !""#Application at 20.

4 Decision (D.) 12-12-030 at 42; Application at 4.

5 !""#D.16-04-006; Application at 4.

CalCCA protests the Application on the grounds the utility has fallen short of demonstrating the entirety of the relief PG&E seeks meets its burden. CalCCA has identified certain issues below that should prevent immediate adoption of the relief requested in the Application, including in particular:

1) PG&E's RA sales activity during the record year, including its efforts to sell excess RA; its transfer of excess RA from the PABA to the NSGBA; and corresponding accounting entries;

2) The reasonableness of PG&E's contract amendments related to the Alpine Solar, Agua Caliente Solar and Daggett 2 BESS projects, and the Poblano Energy Storage project, and the vintaging of those contracts for purposes of cost recovery;

3) Changes to PG&E's retained capacity formula in the Retained RA Tracker; and

4) PG&E's use of "banked" renewable energy credits from prior years to meet its Minimum Retained Renewable Portfolio Standard (RPS) requirement in the record year, and its allocation of the value of those credits to Power Charge Indifference Adjustment (PCIA) vintages.

CalCCA respectfully requests the Commission set this matter for hearing to fully examine these issues together with any other issues that may arise during the course of this proceeding. CalCCA further requests the Commission modify PG&E's proposed list of scoping issues to expressly indicate a thorough review of PG&E's 2024 RA activities is in scope in this proceeding.

I.! CALCCA HAS A DIRECT, CLEAR, REAL, PRESENT, TANGIBLE, AND PECUNIARY INTEREST IN THE OUTCOME OF THIS PROCEEDING

As noted above, CalCCA represents the interests of 24 community choice aggregators (CCAs) in California, including 11 CCAs that serve PG&E's delivery service customers. Except for San Jose Clean Energy (SJCE) and CleanPowerSF, each of those 11 CCAs is governed by a

Board of Directors, comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council. CleanPowerSF is the CCA for the City and County of San Francisco, which the San Francisco Public Utilities Commission operates. SJCE is the City of San José's CCA program, which the San José Energy Department administers. While CalCCA's advocacy frequently benefits both bundled and unbundled customers, the CCAs are the sole advocates for their customers and their local energy programs before this Commission.

CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from investor-owned utilities. As such, CCA customers in PG&E's service territory must pay the same electric distribution, transmission and non-bypassable rates as PG&E's bundled customers. However, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to increase electric vehicle use, procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation, and achieve other local goals.

CCA and other unbundled customers are also subject to several non-bypassable charges, including the PCIA. The Commission adopted the PCIA to ensure that when investor-owned utility (IOU) customers depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs—but only those costs."[6]

The Commission initially determined the level of the PCIA during the 2024 record period in D.23-12-022 based in part on a forecast of the above-market costs stemming from PG&E's generation portfolio over the course of that year. Prior to D.18-10-019, the PCIA rate was set only based on forecasts and not trued-up for unbundled customers—only bundled customers' rates were

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6 !""#D.18-10-019 at 3.

subject to a true-up. Decision 18-10-019 requires that PG&E true up the forecasted costs (net of forecasted market revenues or imputed revenues) approved in D.23-12-022 with the actual recorded costs (net of actual market revenues or imputed revenues) for PCIA-eligible resources.[7] It also requires PG&E to true up the revenues it forecasted it would receive from both bundled and departing load customers over the course of 2024 with the actual revenues it received.[8] This true-up occurs by comparing the forecasted costs and revenues to the recorded costs and revenues within the PABA.

As noted in more detail below, issues relating to whether the entries that PG&E recorded in the PABA (and the ERRA) are reasonable, appropriate, accurate, correctly stated, and in compliance with Commission decisions are within scope in ERRA Compliance proceedings, including this docket.[9] Moreover, PG&E's management of its generation portfolio and its third-party contracts, including its management, procurement, and sales of its RA and RPS resources, as well as its compliance with Commission-approved procurement and resource sales frameworks, directly impact the costs and revenues recorded to the PABA, which in turn impacts PCIA rates. To the extent PG&E's management of its generation portfolio and third-party contracts during the record period was not reasonable or in compliance with Commission decisions, CCA customers (customers of CalCCA's members) might have paid higher PCIA rates than they should have paid. CalCCA therefore has a direct, clear, real, present, tangible, and pecuniary interest in the outcome of this proceeding.

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7 !""#$%. at Ordering Paragraphs (OPs) 7 and 8.

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9 !"" '(($)*"%# +, - - $(($,*"./(# !0,1$*)# 2"-,#3*%# 456$*), A.24-02-012 (June 12, 2024), at 3; Application at 20.

Finally, it is important to note that the true-up of the PCIA via the PABA reflects the full amount of above-market costs recovered from ***H('C***bundled service and departing load customers. All above-market costs for PG&E's PCIA-eligible generation portfolio are paid by both bundled and unbundled customers, which share a portion of the PCIA revenue requirement obligations. The ERRA revenue requirement includes the remaining, at-market portion of the forecasted procurement costs for PG&E's bundled customers. Therefore, as will become evident over the course of this proceeding, many of CalCCA's interests in this case are closely aligned not only with those of PG&E's unbundled customers, but also with those of PG&E's remaining bundled customers.

II.! GROUNDS FOR PROTEST

CalCCA has identified several preliminary issues in the Application that impact the interests described above. CalCCA is still examining the Application, conducting discovery,[10] and communicating with PG&E to better understand and analyze the utility's recorded entries for 2024. CalCCA reserves the right to address and protest additional issues within the scope of this proceeding as they arise through continued review, analysis, discovery, and investigation of all aspects of the Application and supporting testimony.

A.! PG&E's Record Year RA Sales Activity Impacts CalCCA's Interests

PG&E's testimony presents the utility's RA activities during the 2024 record period.[11] PG&E's RA procurement and sales activities, as well as its accounting of Sold RA, Unsold RA, and Retained RA in the PABA, impacts the PCIA rates CCAs' customers pay. Therefore, as in prior ERRA Compliance proceedings, CalCCA will investigate PG&E's 2024 RA activities and

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[10] As of the filing of this Protest, CalCCA has already issued 48 discovery requests to PG&E, in addition to its Master Data Request.

[11] !""#PG&E Prepared Testimony at 8-6 to 8-9; 12-11 to 12-15.

determine whether those activities and associated accounting entries are reasonable, appropriate, correct, and consistent with applicable Commission decisions.

Based on its preliminary review of PG&E's Application and supporting testimony, however, CalCCA is particularly concerned by PG&E's use of excess RA to meet its system reliability incremental procurement targets in 2024[12]—an issue that parallels the core controversy between CalCCA and PG&E in PG&E's pending 2022 ERRA Compliance proceeding (A.23-02-018).[13] While PG&E is permitted to use excess RA from existing PCIA-portfolio resources to meet the incremental procurement targets established by D.21-03-056 and D.21-12-015 to address summer reliability concerns, PG&E may do so ***() #5*&+'12**** making reasonable attempts to sell that excess RA to other load-serving entities (LSE), such as CCAs.[14] Those transfers result in a credit to PABA and a debit to NSGBA.[15] The reasonableness of PG&E's attempts to sell excess RA, and its accounting entries reflecting both RA sales and any transfers of excess RA from the PABA to the NSGBA, therefore affect CCAs' interests.

CalCCA will investigate PG&E's 2024 RA activities—including its efforts to identify excess RA, its attempts to sell excess RA capacity once it identified excess RA, and its transfer of excess RA capacity to the Reliability OIR subaccount of the NSGBA—to ensure PG&E optimized its RA portfolio, made reasonable attempts to sell excess RA capacity to other LSEs, conducted RA sales using the processes described in its BPP, and made the appropriate entries to its balancing accounts. As CalCCA explains in more detail in Section III of this Protest, PG&E's record period

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12 !""#$%. at 12-15.

13 CalCCA also investigated the same issue in PG&E's pending 2023 ERRA Compliance case (A.24-02-012), and following its review, did not dispute PG&E's sales activities during the record year.

14 !""#PG&E Prepared Testimony at 12-15.

15 &7$%8#

RA activity, including each of the issues listed above, are relevant to multiple scoping issues PG&E identifies in its Application, including proposed Scoping Issues 1, 3 and 5.

B.! PG&E's Alpine Solar, Agua Caliente Solar, Daggett 2 BESS, and Poblano Energy Storage Project Contract Amendments Impact CalCCA's Interests

PG&E requests Commission review and approval of four contract amendments in this proceeding. The first three contracts are with projects owned by Clearway Energy (Alpine Solar, Agua Caliente Solar, and Daggett 2 BESS), and the fourth is with Poblano Energy Storage, LLC (collectively, "contract amendments"). The Commission should evaluate not only whether those amendments are reasonable and should be approved, but whether those amendments reflect material modifications from the contracts' original terms, requiring re-vintaging of the contracts for purposes of cost recovery.

A key tenet of the Commission's PCIA framework is that when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs—but only those costs."[16] Departed customers are not responsible for procurement costs associated with resource commitments made after they have departed. To effectuate this policy in the context of renegotiated and amended contracts, the Commission has indicated that a contract should be assigned a new vintage year when the utility modifies material terms of a resource generation contract.[17]

The vintaging of a contract turns on when the utility made the contractual commitment and relatedly when utility customers have departed for purposes of determining "responsibility" for

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16 !""#D.18-10-019 at 3.#

17 !""# Resolution E-4841 at 10 (determining, following review of Ivanpah solar contracts and amended terms, that the amendments did not affect material terms and therefore declining to examine the vintaging of the contracts).

causing the utility to enter into the contractual commitment.[18] The Commission has determined, with respect to power purchase agreements, that a resource "commitment" is made in relation to the execution and effectiveness of the underlying contract.[19] In the context of an ***&4 1) / 1/ **** contract, the Commission has implicitly acknowledged that changes to a contract that are "the result of a buy-out, buydown or renegotiation" would affect customer cost responsibility, whereas "Commission ordered" extensions would not affect customer cost responsibility.[20]

PG&E's contract amendments therefore impact CalCCA's interests because those amendments could trigger a change in the set of customers that are responsible for the costs associated with the underlying contract. CalCCA will issue discovery to examine the four contract amendments PG&E submits for Commission review in this proceeding, and to evaluate whether those amendments include material modifications. To the extent the amendments include material modifications to the underlying contract, CalCCA may address the proper vintaging of the contracts through testimony and/or briefing, as necessary. This issue is reflected in PG&E's proposed list of Scoping Issues as Scoping Issue 7.

C.! PG&E's Retained RA Accounting Impacts CalCCA's Interests

PG&E commits resources to meet its RA obligations on behalf of its bundled customers. When a resource's capacity is assigned to PG&E for meeting its bundled customer RA program obligations, it is considered "Retained" RA. In contrast, when a resource's capacity is sold to

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18 !""#D.04-12-048 at 55 (explaining that a CCA customer would be responsible for certain costs until the IOU's responsibility to plan on behalf of that CCA customer ends); D.08-09-012 at 59 (stating "[t]he law permits the recovery of stranded costs from those customers who are responsible for stranded costs related to resource and contractual commitments made by the IOU up until the time of the customer's departure and . . . departing customers should bear no cost responsibility for such commitments the IOU makes after their departure.")

19 !""9# "8)89# D.08-09-012 at 66 ("We will also adopt SCE's related proposal that 'the time a commitment is made' is when the IOU executes a contract. . . ").

20 !""#D.05-01-031 at 39.

another LSE, the RA is considered “Sold” RA, and when a resource’s capacity is not sold or used by PG&E, it is considered “Unsold” RA.[21] PG&E records Retained RA in the PABA at the market price benchmark, and records Sold RA in the PABA at the sales price for each Sold RA transaction.[22] PG&E’s RA entries, therefore, directly impact the PCIA rates CCA customers pay.

The Commission’s RA program includes three distinct obligations: System, Local, and Flexible RA. In its testimony, PG&E indicates it has “updated the retained capacity formula in the Retained RA Tracker to improve the accuracy of PG&E’s 2024 Retained RA accounting entries to reflect the use of the three RA benchmark types (i.e., market price benchmark values for System RA, Local RA, and Flex RA).”[23] But PG&E does not explain how it has changed the retained capacity formula or elaborates on the impact of its modifications. CalCCA will investigate PG&E’s changes to the retained capacity formula to determine whether those changes are reasonable, appropriate, accurate and consistent with prior Commission decisions. This issue is relevant to PG&E’s proposed Scoping Issue 3: “Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate and in compliance with Commission decisions.”

D.! PG&E’S Use of Banked Renewable Energy Credits to Meet Its Minimum Retained RPS Requirement Impacts CalCCA’s Interests

In its 2024 ERRA Forecast case (similar to the 2023 ERRA Forecast case), PG&E explained its bundled customer Retained RPS position for 2024 would be lower than its Minimum Retained RPS requirement (RPS compliance target) for the same year.[24] PG&E proposed to use

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21 !""#PG&E Prepared Testimony at 8-8.

22 &7$%8

23 !""#PG&E Prepared Testimony at 12-12.

24 !""#A.23-05-012, PG&E Prepared Testimony at 9-17 to 9-24.

banked Renewable Energy Credits (REC) from prior years to meet its projected shortfall and to value the REC transfer at the RPS Adder for the forecast year (PG&E's "Minimum Retained RPS Methodology").[25] The Commission approved PG&E's proposed Minimum Retained RPS Methodology in D.23-12-022.[26]

In its testimony in this proceeding, PG&E presents its Sold, Unsold and Retained RPS, as well as its Minimum Retained RPS recorded to the PABA in 2024.[27] As anticipated, PG&E used surplus RECs from years prior to 2024 to meet its Minimum Retained RPS requirement.[28] CalCCA will investigate PG&E's RPS entries to the PABA, including the quantities of banked RECs PG&E transferred, the value PG&E assigned to those RECs, and the impact of those transfers on PCIA vintages, to ensure PG&E's entries are reasonable, appropriate, accurate and consistent with prior Commission decisions, including D.23-12-022. These issues are relevant to PG&E's proposed Scoping Issue 3: "Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate and in compliance with Commission decisions."

E.! Other Issues that Require Further Investigation and Analysis

CalCCA hopes to work with PG&E over the course of this proceeding to review PG&E's workpapers and better understand, investigate, and potentially submit testimony regarding various components of the Application, including but not limited to:

- Whether PG&E's accounting of costs associated with various procurements are correctly, appropriately, and accurately recorded to ERRA and PABA in compliance with Commission decisions;

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26 !""#D.23-12-022 at OPs 1, 3.

27 !""#PG&E Prepared Testimony at Table 12-1, page 12-7.

28 !""#$%. at 12-8.

- Whether the contract amendments PG&E describes in its testimony (beyond the contract amendments discussed above) reflect material modifications from their original terms and therefore should be revintaged;

- The resolution of PG&E's internal audit of PCIA customer vintaging processes and controls;

- Whether PG&E's accounting of CAISO settlement charges and revenues are correctly, appropriately, and accurately recorded to ERRA, PABA and other balancing accounts in compliance with Commission decisions;

- PG&E's unrealized sales and revenues from 2024 PSPS events and its associated accounting; and

- GTSR-related issues such as whether revenue from GTSR customers was booked to the correct balancing accounts.

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

A.! The Commission Should Modify PG&E's Proposed List of Scoping Issues to Expressly Indicate a Thorough Review of PG&E's 2024 RA Activities is in Scope in this Proceeding

1.! In its pending 2022 and 2023 ERRA Compliance Proceedings, PG&E has opposed a thorough review of its record year RA activities and asserted that review is beyond the scope of the proceeding.

PG&E's Application proposes the following issues for consideration in this proceeding:[29]

1) Whether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4):

   1. Utility-Owned Generation Facilities, including for the 2023 Belden and Caribou 1 Powerhouse outages and two 2023 Diablo Canyon Power Plant maintenance outages; and

   2. Qualifying Facilities (QF) Contracts and Non-QF Contracts;

   If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?

[29] !""#Application at 17-18.

2) Whether PG&E achieved least-cost dispatch of its energy resources and economically-triggered demand response programs pursuant to SOC 4;

3) Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions;

4) Whether PG&E's greenhouse gas instrument procurement complied with its Bundled Procurement Plan;

5) Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan;

6) Whether the costs incurred and recorded in the following accounts are reasonable and in compliance with the applicable tariffs and Commission directives:

    1. Green Tariff Shared Renewables Memorandum Account;

    2. Green Tariff Shared Renewables Balancing Account;

    3. Disadvantaged Community – Single Family Solar Affordable Homes Balancing Account;

    4. Disadvantaged Community – Green Tariff Balancing Account;

    5. Community Solar Green Tariff Balancing Account;

    6. Centralized Local Procurement Sub-Account and;

7) Whether the contract amendments related to the Alpine Solar, Agua Caliente Solar, and Daggett 2 BESS Projects, and the Poblano Energy Storage Project, are reasonable and should be approved;

8) Whether there are any safety considerations raised by PG&E's Application, and;

9) Review of unrealized sales and revenues from PG&E's 2024 PSPS events.

The Commission adopted a substantially similar list of scoping issues in PG&E's pending 2022 ERRA Compliance proceeding.[30] Over the course of that proceeding, however, PG&E has repeatedly taken the position that parties' attempts to investigate its 2022 RA sales efforts beyond

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30 ' (($)*"%#+, - -$(($,*"./(#!0,1$*)#2"- ,#3*%#456$*), A.23-02-018 (June 2, 2023), at 2-3.

the solicitations required by its BPP are beyond the scope of that proceeding.[31] In a similar vein, in PG&E's 2023 ERRA Compliance proceeding, PG&E again opposed CalCCA's efforts to clarify that a thorough review of PG&E's attempts to sell excess RA was in scope in that proceeding.[32]

CalCCA disagrees with PG&E's interpretation of the scope of ERRA Compliance proceedings and maintains that the scope permits a review of PG&E's attempts to sell excess RA in the record year, including ***HA'*) ('*#$4 $1/ *(*** the RA sales solicitations required by PG&E's BPP.[33] The ***! / 4 $) $ '2&'$ 1*N&; *EA/ @1O*9 A#$) @9 1P= "1) $) @B$ %(: 125*(2*3 &#$(2) $&*3 (4 4 A) $5* 3 C($%A*! . . (%$&$( )*** in A.23-02-018 confirms CalCCA's view. That ruling, which followed extended motion practice regarding the scope of PG&E's 2022 ERRA Compliance proceeding—authorized CalCCA to initiate discovery on the issues of:

- PG&E's RA sales solicitations in 2022;
- PG&E's transfer of excess RA from its PCIA eligible resource portfolio to its Cost Allocation Mechanism (CAM) portfolio; and

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31 2 , :$, *# : , # ! : . $; "# < , . :$, *(# , =# :>"# <. "13. "%# ? $. "0:# @"(:$ - , *A# , =# B. $3*# ! >5"A# , *# 7">36=# , =# :>"# +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, *# 7A# <30$=$0# C3(# 3*%# D6"0: . $0# + , - 13*A9 A.23-02-018 (Oct. 6, 2023), at 4-6; <30$=$0# C3(# 3*%# D6"0: . $0# + , - 13*A/(# E F # GHIDJ# 4"(1 , *("# : , # :>"# 2 , :$, *# , =# :>"# +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, *# =, . #K==$0$36# L , :$0"9# A.23-02-018# (Jan. 25, 2024), at 3-4M# <30$=$0# C3(# 3*%# D6"0: . $0# + , - 13*A/(# E F # GHIDJ# 4"(1 , *("# : , # :>"# 2 , :$, *# , =# :>"# +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, *# =, . # + , - - $(($, *# 4"N$"O# , =# ' % - $*$(: . 3:$N"# P3O# Q5%) "/(# DN$%"*:$3 . A# 456$*) (9 A.23-02-018# (Mar. 11, 2024)9 at 12-24; Q , $*: # 4"1 , . :# 7A# <30$=$0# C3(# 3*%# D6"0: . $0# + , - 13*A# E F # GH# DJ# 3*%# :>"# +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, *9# A.23-02-018# (Feb. 14, 2024), at 2-3.

32 <CRD# 4"16A# : , # <. , :"(:(, A.24-02-012 (Apr. 15, 2024).

33 +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, */(# 4"(1 , *("# : , # <30$=$0# C3(# 3*%# D6"0: . $0# + , - 13*A/(# 2 , :$, *# : , # ! : . $; "9 A.23-02-018 (Oct. 23, 2023); +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, */(# 2 , :$, *# : , # K=="# . # DS>7$:(# $*: , # DN$%"*0"# 3*%# ' % - $:# $*: , # :>"# 4"0 , . %9 A.23-02-018 (Jan. 18, 2024); +36$=, . *$3# + , - - 5*$:A# +>, $0"# ' ((, 0$3:$, */(# 2 , :$, *# =, . # + , - - $(($, *# 4"N$"O# , =# ' % - $*$(: . 3:$N"# P3O# Q5%) "/(# DN$%"*:$3 . A# 456$*) (9# A.23-02-018 (Feb. 23, 2024).

- PG&E's attempts to sell excess existing, PCIA-eligible RA resources through the commercial processes of its BPP.[34]

As CalCCA's pleadings filed in PG&E's 2022 ERRA Compliance proceeding explain in detail, PG&E's record-year RA activities, including the timing and manner of its efforts to sell excess RA through both solicitations and other sales processes permitted by the BPP, are relevant to Scoping Issues 1, 3 and 5 in the 2022 ERRA Compliance proceeding, which substantially mirror PG&E's proposed Scoping Issues 1, 3 and 5 in this proceeding.[35]

2.! PG&E's record year RA activities, including the timing and manner of its efforts to sell excess RA, are relevant to the question of whether PG&E prudently managed its RA portfolio (Scoping Issue 1).

Proposed Scoping Issue 1 in the Application, asks "[w]hether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to SOC 4: a) Utility-Owned Generation Facilities, including the 2023 Belden and Caribou 1 Powerhouse outages and two 2023 maintenance outages at Diablo Canyon Power Plant; b) Qualifying Facilities (QF) Contracts and Non-QF Contracts. If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?"[36]

At a high level, Scoping Issue 1 requires the Commission to evaluate whether PG&E prudently administered and managed its generation portfolio (UOG and contracted resources) in the record year. As a part of that broad evaluation, the Commission must assess whether PG&E

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34 '%-$*$(:.3:$N"# P3O# Q5%)"/(# 456$*)# 4"IK1"*$*)# ?$(0,N".A# =,.# +36$=,.*$3# +,--5*$:A# +>,$0"# '((,0$3:$,*9 A.23-02-018 (Jul. 26, 2024).

35 +36$=,.*$3#+,--5*$:A#+>,$0"#'((,0$3:$,*/(#2,:$,*#:,#K=".#DS>$7$:(#$*:,#DN$%"*0"#3*%#'%-$:#$*:,# :>"#4"0,.%, A.23-02-018 (Jan. 18, 2024), at 7-16; +36$=,.*$3#+,--5*$:A#+>,$0"#'((,0$3:$,*/(#2,:$,*#=,.# +,--$(($,*#4"N$"O#,=#'%-$*$(:.3:$N"#P3O#Q5%)"/(#DN$%"*:$3.A#456$*)(9#A.23-02-018 (Feb. 23, 2024), at 11-23.

36 !""#Scoping Memo at 2.

administered and managed its RA resources prudently. That prudence assessment, in turn, includes assessing whether PG&E made reasonable efforts to ensure it received value for all its RA resources, a key consideration in determining whether PG&E has prudently managed its generation portfolio.

The Commission applies several standards to assess the prudence of PG&E's management and administration of its generation portfolio, including SOC 4, the Commission's Good Utility Practice standard and the "reasonable manager" standard.[37] SOC 4 requires utilities to prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[38] The Commission has stated that prudent contract administration consistent with SOC 4 requires the utility "dispose of economic long power"—in other words, sell excess resources—among other activities.[39] In a similar vein, the "Good Utility Practice" standard requires utilities act consistent with:

> "[A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition."[40]

Lastly, the broad "reasonable manager" standard requires utilities act in a manner that "comport[s] with what a reasonable manager of sufficient education, training, experience and skills using the tools and knowledge at his disposal would do when faced with a need to make a decision and

37 !""9#"8)89#D.20-12-036 at 9 (in SDG&E's 2018 ERRA Compliance proceeding, finding SDG&E complied with the Good Utility Practice and reasonable manager standards).

38 !"" D.02-10-062, Conclusion of Law 11.

39 !"" D.02-12-074 at 54; (""#36(, D.05-04-036 at 24.

40 !"" D.02-12-069, Attachment A at 5.

act."[41] Each of these standards permit the Commission to review whether the utility maximized the value of its RA resources for the benefit of its customers during the record period.

In addition, as referenced in Scoping Issue 1, the Commission must determine whether PG&E managed its resource portfolio in compliance with all applicable Commission decisions, including D.21-12-015. Decision 21-12-015 requires PG&E make reasonable attempts to sell its excess RA capacity to other LSEs before counting that capacity towards its incremental system reliability procurement targets.[42] PG&E's efforts to sell its excess RA during the summer of the record year and realize the value of those resources for the benefit of its customers, therefore, is relevant to the assessment the Commission must make under Scoping Issue 1.

In its 2022 ERRA Compliance proceeding, PG&E argues D.21-12-015 "does not create a separate or additional requirement beyond Appendix S" and asserts Appendix S "is the upfront reasonableness standard by which PG&E's compliance is measured for the management and sale of RA in this proceeding."[43] In support, PG&E points to Commission Resolution 4998-E approving Appendix S and the Commission's subsequent disposition of PG&E's Advice Letters 6306-E and 6306-E-A (collectively, "Appendix S Justification ALs"), claiming that disposition "affirms that Appendix S contains the CPUC-approved upfront reasonableness standard for conducting RA sales, including in connection with the Emergency Reliability OIR procurement orders."[44] In essence, PG&E suggests the Commission cannot scrutinize its RA sales activities during the record period in an ERRA Compliance proceeding beyond confirming PG&E carried out the solicitations required by Appendix S.

41 !"" D.90-09-088 at 499.

42 !"" D.21-12-015 at 183-184.

43 <CRD#2 ,:$,*#:,#!:.$;"9#A.23-02-018 (Oct. 6, 2023), at 4.

44 &%. at 6.

PG&E overstates the effect of Resolution 4998-E and the Commission's disposition of the Appendix S Justification ALs. Nothing in Resolution 4998-E or the Commission's disposition of the Appendix S Justification ALs narrows the scope of ERRA Compliance proceedings or precludes parties (and the Commission) from investigating whether PG&E prudently managed its RA sales during the record period.

Ultimately, PG&E's management of its generation portfolio—and specifically the efficiency of PG&E's sales of excess RA—directly contributes to the rates customers pay. That is because PG&E's sales of RA from its PCIA portfolio drive the quantity of Sold and Unsold RA it records, which in turn impacts PG&E's PABA balance—a key component of the PCIA rates PG&E's customers (bundled and unbundled) pay. In addition, the reasonableness of PG&E's attempts to sell excess RA has larger implications for other LSEs in its service territory, who face penalties if they do not procure sufficient RA to meet compliance obligations. Under the constrained conditions that characterize the state's RA market, PG&E's efforts to maximize its sales of excess RA are especially relevant to whether PG&E prudently managed its resource portfolio—not only to lower costs to customers but also to ensure excess capacity is available to meet regional RA needs.

Finally, while the Commission may evaluate changes to PG&E's Bundled Procurement Plan in the recently opened PCIA OIR (R.25-02-005),[45] this ERRA Compliance proceeding is the only appropriate proceeding for the Commission to review the prudence of PG&E's management of its RA portfolio during the summer of the record year. Section 454.5(d)(2) expressly permits the Commission to "establish a regulatory process to verify and ensure that each contract was

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[45] K.%".#&*(:$:5:$*)# 456"-3;$*)#:,# F1%3:"# 3*%# 4"=,.-# D*".)A# 4"(,5.0"# 4"0,N".A# '00,5*:# 3*%# <,O".#+>3.)"#&*%$=="."*0"#'%T5(:-"*:#<,6$0$"(#3*%#<.,0"(("(, R.25-02-005 (Feb. 26, 2025), at 24.

administered in accordance with the terms of the contract[.]"[46] That process is the ERRA Compliance process. In an ERRA Compliance proceeding, parties can contest whether PG&E followed SOC 4 and prudently managed its resources in making RA sales during the record year. Because the question involves actions PG&E should have taken, but did not pursue (***$QQ*** a retrospective review of PG&E's actions during the record year), the ERRA Compliance application and review process is the only available forum for parties to probe that question.

3.! PG&E's record year RA activities, including the timing and manner of its efforts to sell excess RA, are relevant to whether PG&E's entries recorded in the PABA are reasonable, appropriate, accurate, and in compliance with Commission decisions (Scoping Issue 3)

Proposed Scoping Issue 3 in the Application asks "[w]hether the entries recorded in the ERRA and the [PABA] are reasonable, appropriate, accurate, and in compliance with Commission decisions."[47] The Commission has broad latitude to consider PG&E's activities impacting those entries. Among the myriad activities informing Scoping Issue 3 is PG&E's transfer of excess RA capacity from the PCIA to CAM in 2024, and associated accounting entries, which PG&E describes in its Prepared Direct Testimony.[48] The reasonableness of PG&E's attempts to sell excess RA during the summer of 2024 is well-within the scope of this proceeding because that issue ultimately impacts the entries PG&E made to its balancing accounts, including the PABA during the 2024 record period. Those entries directly contribute to the rates PG&E's customers ultimately pay.

To be more specific, PG&E's attempts to sell its excess RA impact not only the magnitude of PG&E's credit to PABA resulting from the transfer of excess RA to CAM, but also the actual

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46 Cal. Pub. Util. Code § 454.5(d)(2).

47 !"" Scoping Memo at 2-3.

48 !"" PG&E Prepared Testimony at 12-15.

amount of RA capacity PG&E sold during the record year. Ultimately, PG&E's Actual Sold RA (compared to the amount of Sold RA it had forecasted it would sell) is a key factor driving whether an over- or under-collection exists in the PABA, which in turn drives the revenue requirement for the following year's PCIA rates that PG&E's customers pay.[49]

The facts of PG&E's attempts to sell excess RA during the summer of the record year therefore go to whether PG&E's PABA entries are "reasonable, appropriate, accurate, and in compliance with Commission decisions." Put differently, should the Commission find PG&E's attempts to sell its excess RA capacity were) ('*easonable, and could have resulted in a different PABA balance at the end of the record year due to increased sales of RA, it might determine PG&E's PABA entries were not "reasonable, appropriate, accurate and in compliance with Commission decisions."

4.! PG&E's record year RA activities, including the timing and manner of its efforts to sell excess RA, are relevant to whether PG&E administered resource adequacy sales consistent with its BPP (Scoping Issue 5)

Scoping Issue 5 asks "[w]hether PG&E administered resource adequacy procurement and sales consistent with its [BPP]."[50] Facts related to PG&E's RA sales in 2024—including PG&E's RA positions; the calculation of its RA positions; the timing of PG&E's calculation of its RA position; the timing and outcomes of its RA solicitations; and PG&E's attempts to sell its excess RA capacity through both solicitations and other non-solicitation transactions—are each relevant

[49] PG&E's PCIA rates are set in the ERRA Forecast proceeding based on: (1) the Indifference Amount (the difference in the forecast year between the cost of PG&E's supply portfolio and the market value of that portfolio); and (2) the year-end balance in the PABA. The Indifference Amount and the year-end PABA over- or under-collection are added together to form the PABA revenue requirement underlying PCIA rates.

[50] !"" Scoping Memo at 3.

to Scoping Issue 5, because those facts go to whether PG&E conducted RA sales consistent with Appendix S of its BPP.

In its 2022 ERRA Compliance proceeding, PG&E has argued Scoping Issue 5 permits only a review of whether PG&E complied with the mandatory solicitations ***21RA$21/*** by Appendix S of its BPP,[51] and that scrutiny of PG&E's RA activities beyond those mandatory solicitations would constitute a collateral attack on the Commission's prior decisions.[52] PG&E's position is unsupported. While the Commission's prior decisions affirm PG&E's sales framework, nothing in those decisions insulates PG&E from scrutiny of its treatment of excess RA during the record period consistent with that framework—including its sales of RA through both solicitations and other transactions beyond solicitations—in an ERRA Compliance proceeding.

5.! While PG&E's record year RA activities are relevant to multiple of the scoping issues proposed in PG&E's Application, to avoid parties rehashing scoping arguments in this proceeding, the Commission should clarify that a thorough review of PG&E's attempts to sell excess RA is within the scope of this proceeding.

As explained above, the facts of PG&E's attempts to sell excess RA are relevant to multiple scoping issues proposed in PG&E's Application. The bottom line is that there is simply no other proceeding in which the Commission might conduct a backward-looking assessment of those activities and scrutinize their impacts on bundled and unbundled customers.

In the interest of clarity, however, and to avoid parties rehashing the same scoping arguments they made in PG&E's 2022 ERRA Compliance proceeding, CalCCA recommends the Commission modify PG&E's proposed list of scoping issues to expressly indicate a thorough review of PG&E's attempts to sell excess RA in 2024—including the timing and manner of its

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[51] # !"" <CRD#4"(1,*("#:,#+36++'/(#2 ,:$,*#=,.#+, - -$(($,*#4"N$"O9 A.23-02-018 (Mar. 11, 2024), at 17.

[52] &%. at 12-17.

sales of excess RA through both the solicitations required by PG&E's sales framework and through any other means permitted by that sales framework—is in scope of this proceeding. The following specific revision to PG&E's proposed Scoping Issue 5 would achieve this end:

> 5. Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan, including whether PG&E made reasonable attempts to sell excess RA consistent with its Bundled Procurement Plan

B.! The Commission Should Categorize This Proceeding As Ratesetting

CalCCA agrees with the categorization of this proceeding as ratesetting.[53]

C.! The Commission Should Set This Matter for Evidentiary Hearing

While CalCCA shares PG&E's hope to resolve the issues raised by this Application without hearings,[54] CalCCA agrees that evidentiary hearings may be necessary to present facts related to those issues, and therefore requests that the Commission set this matter for hearing.

D.! The Commission Should Adopt CalCCA's Proposed Procedural Schedule

PG&E's proposed procedural schedule would require CalCCA (and Cal Advocates and other intervenors) to file testimony on September 15, 2025, for PG&E to file rebuttal testimony on October 20, 2025, and for all parties to conduct settlement negotiations and prepare for evidentiary hearings thereafter. While PG&E's proposed schedule resembles its proposal from last year's ERRA Compliance proceeding (and CalCCA supported that proposal with minor modifications), the Commission should not adopt PG&E's proposal here. PG&E's proposed schedule clusters testimony filings and an evidentiary hearing at the very time that the IOUs' expedited ERRA Forecast proceedings are most busy (the September to November time frame). In recent years, those proceedings have been even busier than usual in the fall. Parties have been required to not

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53 !""#Application at 17.

54 !""#$%.

only review and address the IOUs' Fall Updates (an accelerated process that occurs annually) but also digest and respond to new policy proposals in those Updates, while also responding to Administrative Law Judge rulings requesting comments on substantive issues related to the Forecast cases. In short, the September to November time frame tends to be particularly demanding for anyone involved in the IOUs' ERRA Forecast proceedings. CalCCA's small team of experts and counsel are involved in all three IOUs' ERRA Forecast proceedings (in addition to those IOUs' ERRA Compliance proceedings). Therefore, CalCCA respectfully requests the Commission adopt a procedural schedule for this case that minimizes procedural deadlines in the September to November time frame. CalCCA presents its proposed procedural schedule below.

Event	**PG&E Proposal**	**CalCCA Proposal**
Application Filed	**February 28, 2025**	**February 28, 2025**
Cal Advocates and Intervenor Testimony	September 15, 2025	July 16, 2025
Rebuttal testimony served	October 20, 2025	August 18, 2025
Evidentiary Hearings	November 17-21, 2025	Week of August 25, 2025
Concurrent Opening Briefs	December 19, 2025	December 19, 2025
Concurrent Reply Briefs	January 20, 2026	January 20, 2026
Proposed Decision	Q1 2026	Q1 2026
Final Decision	Q1 2026	Q1 2026

IV.! COMMUNICATIONS

CalCCA consents to "email only" service and requests that the following individuals be added to the service list for A.25-02-013 on behalf of CalCCA:

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V.! CONCLUSION

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

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: April 4, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 E)	Application 24-09-014

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PUBLIC ADVOCATES OFFICE MOTION TO AMEND THE SCOPING MEMO TO INCLUDE ISSUES FROM APPLICATION 24-11-007

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April 17, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design (U 39 E)	Application 24-09-014

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PUBLIC ADVOCATES OFFICE MOTION TO AMEND THE SCOPING MEMO TO INCLUDE ISSUES FROM APPLICATION 24-11-007

Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[1] (CalCCA) submits this response in support of The Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) ***3 #.,#%1.#!2- '%4!.0' !51#6,%7!3 '- #!.#!8%1($4' !8&$' &)*#- ! 266(,1+.,#%9: ;<<;==>*** (Motion).[2]

I. THE COMMISSION SHOULD GRANT CAL ADVOCATES' MOTION TO ESTABLISH THIS PHASE II GRC AS THE APPROPRIATE FORUM FOR CONSIDERING RATE STRUCTURES FOR LARGE-LOAD TRANSMISSION-LEVEL CUSTOMERS

CalCCA supports Cal Advocates' request that the Commission amend the scope of this proceeding to include consideration of rate structures for large-load transmission-level customers.

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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 Application (A.) 24-09-014, !"#$%&' ()*+&,-./' 011%&. 2+-%+3'-+' (4.3)'-5.'6&+7%38' 2.4+'-+' 93&$").'9//"./'1:+4'(77$%&,-%+3';<=>>=??@'(Apr. 2, 2025) (Motion).

Inclusion of this issue within the scope of this Phase II General Rate Case (GRC) is appropriate and necessary for a few key reasons.

First, the Phase II GRC will provide the Commission and stakeholders with the correct forum for considering how to avoid undue cost-shifts resulting from the interconnection of large-load customers to Pacific Gas and Electric Company's (PG&E) transmission system. As Cal Advocates explains in its Motion, this issue arises out of PG&E's Application (A.) 24-11-007, in which PG&E proposes a new process for interconnecting large-load transmission-level customers in light of the increased volume of these interconnection applications.[3] Parties to A.24-11-007, including Cal Advocates[4] and the joint community choice aggregators,[5] recommended in A.24-11-007 that rate issues arising from this new customer load should be addressed as part of that proceeding. However, the Commission's Scoping Ruling in A.24-11-007 made clear that topics including "rate structures" and "incremental generation costs" must instead be considered in "other, more appropriate forums."[6]

Consideration of these issues is critical for the Commission to determine the rate structures that will most effectively assign costs associated with these transmission-level interconnections in line with cost causation. In particular, and as Cal Advocates raises in its Motion, rate structures should be in place to reduce the potential for cost shifting to other customers in the event of any stranded costs arising from these interconnections.[7] Given the magnitude of the costs at issue with

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3 9). at 3.

4 6.. %). at 1, 3.

5 A.24-11-007, A./7+3/.'+1'-5.'B+%3-'C+44"3%-D'C5+%&.'(88:.8,-+:/, at 11-12 (Dec. 23, 2024).

6 A.24-11-007, (//%83.)'C+44%//%+3.:E/'6&+7%38'2.4+',3)'A"$%38'+3'!,&%1%&'F,/',3)'G$.&-:%&'C+47,3DE/'A.H"./-'+'947$.4.3-','I.J'G$.&-:%&'A"$.'K?'L,:%11, at 5'(Mar. 11, 2025).

7 Motion at 4.

this new interconnection pathway,[8] the Commission needs a forum for addressing the associated ratepayer implications and options for ratepayer protections. In addition, issues regarding any rate structures for generation service should also be addressed in this forum.

In light of the Commission's conclusion that these rate issues are out of scope in A.24-11-007, this Phase II GRC is the appropriate forum. Phase II GRCs, generally, are the appropriate venue for considering rate design and cost allocation issues for a utility.[9] While this Phase II GRC is scoped to consider a broad range of rate design and cost allocation issues raised in PG&E's Application and Prepared Testimony,[10] PG&E's proposals in this case do not specifically include such rate structures for transmission-level customers. Therefore, the Commission should amend the Scoping Ruling in this case to clarify that these kinds of rate structures are within scope.

In sum, because consideration of rate structures to limit cost-shifting from and for generation service to large-load transmission-level customers is critically important, has been punted from the scope of A.24-11-007, and naturally fits within the scope of this Phase II GRC proceeding, the Commission should grant Cal Advocates' Motion. Specifically, the Commission should:

- Amend the Scoping Ruling to add the three scoping items recommended by Cal Advocates to the scope of this proceeding;[11] and
- Direct PG&E to provide supplemental testimony in this case that proposes rate design solutions to ensure the influx of large-load transmission-level customers indicated by PG&E in A.24-11-007 does not impose unreasonable cost shifts on other ratepayers.

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8 6..'%). ("PG&E states that if all of the anticipated large-load transmission-level customers are connected to the grid and their forecasted load materializes, it could see a 30-fold increase in its transmission level demand compared to total transmission load interconnected between 2014 and 2022").

9 6..'Decision (D.) 20-01-002 at 4, 15.

10 6..'A.24-09-014, (//%83.)'C+4 4%//%+3.:E/'6&+7%38' 2 . 4+',3)'A"$%38, at 2-3 (Mar. 21, 2025).

11 Motion at 7.

II. CONCLUSION

For the foregoing reasons, CalCCA respectfully requests the Commission grant Cal Advocates' Motion.

Dated: April 17, 2025

Respectfully submitted,

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

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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On behalf of
California Community Choice
Association

April 21, 2025

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SUMMARY OF RECOMMENDATIONS

In Track One, the Commission should:

- ✓ Apply any modification to the RA MPB only prospectively to the 2026 RA Forecast MPB to avoid prohibited retroactive rulemaking.
- ✓ To the extent the Commission modifies the RA MPB in Track One, ensure such modification is narrowly tailored to address only the problem identified through substantial evidence – reduced volumes for the RA MPB calculation.
- ✓ In choosing the narrowly tailored “fix,” first apply Staff Proposal Five to combine the RA MPBs, and if the volumes are sufficiently increased, stop there and move to Track Two for a broad review of the PCIA methodology.
- ✓ If the Commission must also implement Staff Proposal One to increase volumes, limit the timeframe expansion to the shortest period to increase the volumes.
- ✓ Establish definitions of affiliate, swap, and sleeve transactions if the Commission decides to exclude such transactions from the RA MPB.
- ✓ Adopt monthly RA MPB values, as proposed in Staff Proposal Four.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[1] and the *Assigned Commissioner's Scoping Memo and Ruling*[2] (Scoping Ruling)*,* the California Community Choice Association[3] (CalCCA) submits this Opening Brief.

I. INTRODUCTION

The Joint Investor-Owned Utilities (Joint IOUs) employ a tactic in Opening and Reply Comments on the Order Instituting Rulemaking (OIR) akin to the Gish Gallop:[4] presenting a flood of arguments, sometimes rooted in mischaracterizations or quotes out of context, to distract from their underlying goal – temporarily changing the resource adequacy (RA) market price benchmark (MPB) to significantly benefit bundled customers. Instead of responding to the flood of arguments in this Opening Brief, which CalCCA has already done in its Opening and Reply Comments on the OIR, CalCCA will address the Track One core issue of evidence-based solutions to address the identified problem of reduced transaction volumes in calculating the RA MPB. CalCCA also explains why those solutions can only be applied prospectively, given the prohibition on retroactive ratemaking.

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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 *Assigned Commissioner's Scoping Memo and Ruling*, R.25-02-005 (Apr. 8, 2025).

3 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.

4 The Cambridge Dictionary defines a "Gish Gallop" as "a style of arguing in which someone tries to win a debate . . . by using so many different arguments so quickly that their opponent cannot answer them, although these arguments may not be true, correct, or reasonable."

The Scoping Ruling reasonably focuses Track One to questions seeking solutions to the reduced volume of transactions received by Energy Division (ED) to calculate the 2025 Forecast MPB. The Scoping Ruling also allows Opening Briefs on the legal issue of retroactive ratesetting, procedural and evidentiary issues, and substantive arguments (in that order).[5] CalCCA therefore provides the following recommendations in this Opening Brief.

First, any modifications to the RA MPB should only be applied prospectively to the 2026 RA MPB Forecast, as applying the modified RA MPB methodology to the 2025 true-up would be prohibited retroactive ratemaking. A modified RA MPB calculation would be the product of "general ratemaking" and, therefore, does not fit into the exception to unlawful retroactive ratemaking carved out in *Southern California Edison Company v. Public Utilities Commission (Edison).*[6] This is because the RA MPB modification being proposed in Track One: (1) would be the product of considering many variables to formulate broad policy; and (2) would have a significant impact on the customers and/or load-serving entities (LSEs) affected. Instead, any new RA MPB methodology adopted in Track One should be applied on a prospective basis only – *i.e.,* to the 2026 Forecast MPB.

Second, Public Utilities Code section 1757 requires the Commission to support any findings, which here should encompass both the problem the Commission seeks to fix and the solutions it adopts, with "substantial evidence." In its Opening and Reply Comments, CalCCA points to the need for transparency and additional data to allow parties to determine the impacts on customers of the potential changes proposed in ED's Staff Report.[7] CalCCA also encourages the Commission to proceed cautiously with any modification to the RA MPB given the limited information in the Staff Report, which ED describes as only "largely correct."[8] Given the limited data and overall record, the Commission must focus only on the findings substantial evidence can support.

Third, if the Commission decides to require the exclusion of affiliate, and swap and sleeve, transactions as proposed in Staff Proposals Two and Three, definitions of those transactions will need to be established to allow the transparent identification of such transactions.

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5 Scoping Ruling, at 3.

6 *Southern California Edison Co. v. Pub. Util. Comm'n,* 20 Cal.3d 813 (1978).

7 R.25-02-005, Appendix A to *Chief Administrative Law Judge's Ruling Adding Energy Division Report to the Record and Setting the Schedule for Comments on the Report* (Feb. 26, 2025) (Staff Report).

8 Staff Report, at 12.

Finally, while the Scoping Ruling (perhaps inadvertently) did not expressly include consideration of Staff Proposal Four regarding using monthly values for the RA MPB, CalCCA continues to support monthly values as set forth in CalCCA's Opening and Reply Comments.[9]

Accordingly, in Track One, the Commission should:

- ✓ Apply any modification to the RA MPB only prospectively to the 2026 RA Forecast MPB to avoid prohibited retroactive rulemaking.
- ✓ To the extent the Commission modifies the RA MPB in Track One, ensure such modification is narrowly tailored to address only the problem identified through substantial evidence – reduced volumes for the RA MPB calculation.
- ✓ In choosing the narrowly tailored "fix," first apply Staff Proposal Five to combine the RA MPBs, and if the volumes are sufficiently increased, stop there and move to Track Two for a broad review of the PCIA methodology.
- ✓ If the Commission must also implement Staff Proposal One to increase volumes, limit the timeframe expansion to the shortest period to increase the volumes.
- ✓ Establish definitions of affiliate, swap, and sleeve transactions if the Commission decides to exclude such transactions from the RA MPB.
- ✓ Adopt monthly RA MPB values, as proposed in Staff Proposal Four.

II. THE COMMISSION SHOULD APPLY A MODIFIED RA MPB ONLY PROSPECTIVELY

Permissible retroactive ratemaking is part of the Commission's ratesetting processes. When it trues up forecasted data with actual data to set rates via balancing accounts, for example, the Commission engages in retroactive ratemaking. California courts have sanctioned such mechanisms as a narrow exception to the broad prohibition against retroactive ratemaking. To qualify for that exception, however, the Commission cannot engage in "general ratemaking". Changing the formula and methodology used to set the RA MBP clearly constitutes "general ratemaking" under California law and therefore cannot be applied retroactively. Courts have defined general ratemaking as rates that: (1) are the product of considering *many variables* to formulate *broad policy*; and (2) have a *significant impact* on customers and/or LSEs. Such rates involve more than an exercise in basic arithmetic to update an established formula with the most recent empirical data. They stem from revenue requirements established in other policy-heavy cases, like general rate cases (GRCs). They change an existing ratemaking formula, financially disrupting customers or LSEs in a manner that would not have occurred in due course under prior ratemaking.

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[9] CalCCA Opening Comments, at 33-34; CalCCA Reply, at 22-23.

In the OIR and Staff Report, the Commission has suggested the 2025 forecast RA MPB was overstated when issued in October 2024 because of reduced trading volume and the inclusion of potentially non-market relevant transactions.[10] The Assigned Commissioner has set Track One to determine whether the Commission should: (1) expand the data considered when determining the RA MPB by extending or eliminating the existing time limits on transaction data considered; (2) combine system, local, and flexible RA into a single RA value when calculating the RA MPB; and/or (3) eliminate data that is duplicative or does not reflect market-based transactions.[11] To answer these questions, the Commission has weighed and will continue to weigh many variables: (1) the best data to approximate the value of capacity attributes in the PCIA-eligible portfolios; (2) the allocation of costs between bundled and unbundled customers that results from that valuation; (3) whether that division achieves customer indifference; (4) whether the RA MPB and PCIA rates more generally are a customer affordability issue; and (5) whether the Staff Proposals are simply results-oriented modifications to subsidize bundled customer rates at the expense of departed customers. The PCIA rates at issue derive from costs set in the IOUs' GRCs (for utility-owned generation (UOG)) and the Commission's most important ratesetting proceedings (the Renewables Portfolio Standard (RPS), Integrated Resource Planning (IRP), and Resource Adequacy (RA) rulemakings). The Commission's retroactive application of a new RA MPB will significantly impact customers and LSEs via swings in billion-dollar revenue requirements. Such impacts would not have occurred as a matter of course under the prior method because the actual value of capacity, to which the forecasted value is compared, *itself* is being revised and cannot be proven empirically.

As set forth in detail below, the Commission should not apply the modified RA MPB retroactively to the 2025 true up because it does not fit into the narrow exception to prohibited retroactive ratemaking. It goes beyond updating an existing formula with the most recent empirical data to revising that formula to achieve broad policy, with significant financial implications. The resulting rates will be the products of general ratemaking and, therefore, cannot be retroactive.

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10 OIR at 13-16; Staff Report at 7-12.

11 Scoping Ruling, at 3.

A. Legal Standard for General Ratemaking and the Narrow Exception to the Prohibition Against Retroactive Ratemaking

California law empowers the Commission to modify rates on a prospective basis only; retroactive ratemaking is "beyond the statutory power of the Commission."[12] While the doctrine does not apply to every action of the Commission, the rule against retroactive ratemaking is a broad and fundamental principle tied to the Commission's core function: setting utility rates. [13] When the Commission is setting rates, as it is in this case,[14] California law only allows backward-looking revisions when the retroactive rates are not "the products of" general ratemaking.[15] As discussed below, making backward-looking revisions by using *a new calculation methodology* is general ratemaking and therefore cannot be applied retroactively.

Case law and Commission precedent illuminate how to determine when a change to settled rates is the product of "general ratemaking" and cannot be applied retroactively. In *Edison*, the California Supreme Court carved out the narrow exception to the rule against retroactive ratemaking when rates were set through an automatic fuel clause adjustment. As an oil embargo helped spark the energy crisis in the early 1970s, the Commission granted SCE's request to include an adjustment clause in its tariffs that permitted billing adjustments to reflect increases in the cost of fuel. The Court explained:

> The clause operated as follows: at regular intervals Edison prepared a forecast of the quantity of fossil fuel it would need to purchase in the ensuing 12-month period under average weather conditions. It then calculated the cost of such fuel at current prices, and compared that figure with the cost of the same quantity of fuel at the prices reflected in its existing base rates. If the difference worked out to .001 cent per kilowatt-hour or more, Edison notified the commission of this fact by filing an "advice letter" requesting authority to increase future billings to compensate for its predicted higher fuel expenses. [16]

SCE was permitted to file the advice letter every three months.

SCE invoked the clause "at every opportunity between May 1972 and December 1974, and in so doing raised its rates no less than 12 times."[17] Through the use of the clause, SCE collected in rates an amount greater than its actual costs by $145.8 million. To put that figure in perspective, at one time, earnings from the fuel clause itself represented more than 56 percent of SCE's systemwide net income

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12 *See, e.g.*, Pub. Util. Code § 728 (authorizing Commission to determine rates "to be thereafter observed and in force"); *Edison*, 20 Cal. 3d at 816 (citing *Pac. Tel. & Tel. Co. v. Public Util. Com*. (1965) 62 Cal.2d 634).

13 *Edison,* 20 Cal. 3d at 816.

14 Scoping Ruling, at 4 (categorizing this proceeding as ratesetting).

15 *Ponderosa Tel. Co. v. Pub. Util. Com.* (2011) 197 Cal.App.4th 48, 63 (citing *Edison,* 20 Cal.3d at 830).

16 *Edison,* 20 Cal.3d at 817-818 (internal citations omitted).

17 *Id.* at 821.

for the entire year. SCE's fuel clause generated outrage and "a sequence of public complaints, investigations, and proposals for reform or abolition of the entire fuel clause procedure."[18] The Commission issued an Order Instituting Investigation (OII) and, as a result of that investigation, created the energy cost adjustment clause (ECAC), a balancing account that operates similar to other balancing accounts common in Commission practice today. The ECAC compared actual energy costs to forecasted energy costs, and adjusted rates with the aim of bringing the balance to zero.[19]

While the ECAC addressed the shortcomings of the original fuel adjustment clause, the massive overcollections accumulated by SCE and the other utilities under the old fuel clause still existed. As part of its investigation, the Commission adopted a proposal from PG&E and required the overcollections be paid back to customers over 36 months in rates. It was this refund that SCE challenged in the appeal leading to *Edison*; SCE expressly disavowed any challenge to the Commission's creation of, and the retroactive operation of, the ECAC itself.[20]

Edison set a general standard for when retroactive rate changes constitute prohibited retroactive ratemaking based on how the rates were set and the nature of their impacts. Focusing on how the original fuel clause adjustment worked, the Court observed "that before there can be retroactive ratemaking there must at least be *ratemaking*."[21] The Court found that because the refunds stemmed from a fuel clause adjustment, general ratemaking had not occurred, and the rule against retroactivity did not protect SCE's overcollections from being refunded.[22] To reach that conclusion, the Court looked to whether the Commission's process and considerations in setting rates constituted true ratemaking, and whether the Commission's action had a significant financial impact on SCE. [23] It determined an advice letter process that automatically adjusts rates based on the predicted costs of fuel did not amount to true ratemaking.[24] It also determined the refunds would have occurred in due course under the old fuel clause; and the amount of the refunds could be verified by simply reviewing SCE's books, meaning the Commission's order left SCE no worse and no better off than it would have been had the Commission not ordered the refunds.[25] "To put it another way, the [C]ommission's decision to

18 *Id.,* at 822.
19 *See id.* at 821-823.
20 *Id.* at 824 (stating "Edison expressly disavows any challenge to the [ECAC].")
21 *Id.* at 817 (emphasis added).
22 *Id.* at 824-831.
23 *Ibid.*
24 *Id.* at 826-831.
25 *Id.* at 824-826, 829.

further adjust those rates so as to compensate for substantial past overcollections may well be retroactive in effect, but it is not retroactive *ratemaking*."[26]

Neither California courts nor the Commission have significantly expanded upon the narrow exception to retroactive ratemaking established in *Edison*.[27] However, in *Ponderosa*, the California Court of Appeals found prohibited retroactive ratemaking had occurred when the Commission retroactively revised a ratesetting formula – a change in methodology – for gains on sale of stock from a telephone company.[28] The rate formula had been set via a rulemaking requiring 66 percent of the proceeds from the sale to be conveyed to ratepayers and 33 percent to shareholders.[29] In an eleven-utility consolidated application seeking to disburse funds from a gain on sale in line with that formula, the Commission revised the formula to convey 100 percent of the proceeds to ratepayers.[30] The court determined the Commission's revision of the formula – set in a rulemaking categorized as ratesetting – "retroactively revises costs that formed the basis for prior general rates," concluding that "[t]his is precisely the type of action prohibited by the retroactive ratemaking doctrine."[31]

The Commission has continued to evaluate the same factors the Court looked to in *Edison*. A line of Commission cases applies the *Edison* exception, finding that the retroactive nature of different balancing accounts, memo accounts, fuel clauses, and other similar mechanisms do not, on their own, constitute general ratemaking, especially when such mechanisms have little effect on rates.[32]

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26 *Id.* at 830 (emphasis in original).

27 *But see Towards Utility Rate Normalization v. Pub. Util. Comm'n* (1988) 44 Cal.3d 870 (determining a major-additions adjustment clause account is not retroactive ratemaking); *Cal. Mfrs. Ass'n v. Pub. Util. Comm'n* (1979) 24 Cal. 3d 251 (determining a rate allocation methodology within an "offset proceeding" is not retroactive ratemaking); *see also* D.92317, 1980 Cal. PUB LEXIS 844, *3 (Oct. 8, 1980) (characterizing *Edison* as a limited exception to the rule against retroactive ratemaking, and reiterating that the rule is broad in its application).

28 *Ponderosa*, 197 Cal.App.4th at 63-64.

29 *Id.* at 54 (citing to D.06-05-041 (as modified by D.06-12-043)).

30 *Id.* at 54, 64.

31 *Id.* at 64-65.

32 *See* D.92317 at *3-5; D.09-06-053, at 9 (June 18, 2009) (recognizing that the Commission OII at issue was not a general ratemaking proceeding, and a memorandum account to track and potentially recover a specific, very limited class of costs is not general ratemaking.); D.01-03-082, at 50 (Mar. 27, 2001) (rejecting arguments that a true-up constituted retroactive ratemaking, recognizing that the true-up served to carry-out legislative intent and did not change any rates); D.04-03-041, 2004 Cal. PUC LEXIS 80, at *14-15 (Mar. 17, 2004) (revised balancing account procedures in question did not adjust general rates set by the Commission based on hindsight review of a utility's earnings, was not part of a general ratemaking proceeding, and had no effect on general rates); 1982 Cal. PUC LEXIS 1270, at *12 (Apr. 28, 1982) (concluding that inclusion of past franchise fees in the utility's proposed rate adjustment did not constitute retroactive ratemaking because over time, inclusion of the past fees would produce the same result as the normal course of business for the utility); D.12-03-026, 2012

Distilling this precedent down, *Edison* and its progeny establish that general ratemaking occurs – and retroactivity is prohibited – when two factors exist:

1. The retroactive rate is the product of true ratemaking that has considered many variables to formulate broad policy and is not simply an exercise in basic arithmetic to reflect verifiable costs; and
2. The impact of the retroactive rate is significant to the customers and LSEs affected and would not have occurred but for the new rates.

Applying each of these factors to the instant case makes clear that ordering the IOUs to apply a new methodology to true-up 2025 rates *is* general ratemaking, and therefore retroactive application is prohibited.

B. Revising the RA MPB Methodology and Applying it to Market Activities in 2025 Constitutes General Ratemaking

If the Commission modifies the RA MPB calculation in Track One, the resulting retroactive PCIA rates would be the product of general ratemaking because they will be: (1) based on a *new methodology* to calculate an *administratively set* benchmark adopted via a *rulemaking proceeding* that will weigh *substantial questions of policy*; and (2) will have a *significant impact on rates* that w*ould not have otherwise occurred.* Such general ratemaking cannot be applied retroactively, as set forth below.

1. Contemplated Revisions to the RA MPB Stem from Consideration of Broad Policy Questions

The broad policy questions implicated in the OIR and Staff Report are a hallmark of general ratemaking under *Edison*. *Edison* demonstrates the clear difference between: (1) a general ratemaking proceeding in which many variables are taken into account and broad policies are formulated; and (2) a "narrowly restricted and semi-automatic functioning of an adjustment clause" set via an advice letter.[33] The Court explains the latter involves isolating and updating one component of customers' rates with more recent "empirical data."[34] The Court endorses the view that, in circumstances where simple arithmetic is at play, it is more efficient to address that one component via a less onerous process, like the advice letter process, than to consider that component in a ratesetting hearing in which all other components are held constant. [35] Stated another way, general ratemaking takes place when a rate mechanism is being revised or adopted and there is "a plenary discussion" of the

Cal. PUC LEXIS 135, at *29-30 (Mar. 8, 2012) (recognizing that evaluating applicability of the rule against retroactive ratemaking requires determination of the origin of the rates underlying refunds being challenged).

33 *Edison,* 20 Cal.3d at 828.

34 *Ibid*.

35 *Id.* at 821, 828-829.

advantages and disadvantages of the rate mechanism. If the variables in the ratemaking formula are just being updated to reflect something like recent prices, a full ratesetting hearing is unnecessary and would be tantamount to "a yearly charade attendant to its application."[36] After all, the purpose of a hearing in general ratemaking proceedings "is to air the policy considerations behind various rate proposals and to establish controverted facts."[37] Such process "serves no purpose when the only business at hand is the application of a mathematical formula to a figure definitively established by reference to the utilities' books."[38]

That "plenary discussion" is precisely the point of the current proceeding. In Track One, the Commission is weighing five different Staff Proposals to change the current methodology of calculating the RA MPB to address increasing transaction volumes aimed at how to best reflect the value of capacity held in the IOUs' generation portfolios.[39] The OIR recognizes the many complex variables the Commission must consider to set that policy, including "[s]hifts in today's energy market costs relative to the contract prices of older resources," how those shifts "can drive changes in the PCIA" and, as a result, "the relative cost share between bundled and departed customers." [40] The OIR notes how "[t]he RA market has experienced extreme increases in the price for system RA, specifically during peak summer months," and how those increases have "led to rapid increases in the RA market price benchmarks in the past few years, which has increased the market value of IOU portfolios compared to the costs of those portfolios, resulting in PCIA shifting from serving as a charge to a credit on the bill of some departed load customers."[41] The OIR discusses the impact of these factors on overall customer indifference and outlines four policy objectives for this case:

1) Consider and identify reasonable improvements to existing ERRA and PCIA rules, mechanisms, and processes to ensure best practices in utility forecasting and other procurement plan activities;
2) Identify ways to mitigate and respond to rate volatility, whether resulting from market conditions or ratemaking constructs;
3) Best ensure indifference among bundled and departed customers; and

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36 *Id.* at 829 (citing *City of Los Angeles v. Public Util. Comm'n* (1975) 15 Cal.3d 680, at 695).
37 *Ibid.*
38 *Ibid*.
39 Staff Report, at 13-17.
40 OIR, at 14.
41 *Ibid.*

4) Provide policy guidance to ensure that individual utility forecast ratemaking proceedings function as efficiently and consistently as possible.[42]

After considering the OIR and issues raised in parties' comments, the Scoping Ruling set Staff's proposed changes to the RA MPB as the focus of Track One to meet these goals.[43]

Clearly these issues are distinguishable from automatic fuel clause adjustments. As in *Ponderosa*, the Commission here is weighing whether and how to *revise* an existing ratemaking formula, specifically the formula set forth in D.19-10-001 requiring ED to true up the RA MPB based on the "volume-weighted average of all IOU, CCA and ESP RA-only market transactions" in the past 12 months.[44] Party Opening and Reply Comments on the OIR have already aired the numerous policy considerations implicated in the Staff Proposals, including: (1) which proposals will best approximate the market value of capacity attributes in the PCIA-eligible portfolios; (2) the division of cost responsibility between bundled and unbundled customers that results from that market valuation; (3) whether that market valuation embodies customer indifference; (4) whether the RA MPB and PCIA rates more generally are a customer affordability issue; and (5) whether the Staff Proposals are simply results-oriented modifications to lower bundled customer rates at the expense of departed customers.

The "business at hand" in this proceeding clearly is far more than "the application of a mathematical formula to a figure definitively established by reference to the utilities' books." [45] The "plenary discussion" of the advantages and disadvantages of Staff's Proposals clearly amount to more than "a yearly charade" attendant to the calculation of the PCIA.[46] In other words, true ratemaking clearly is taking place in this case and cannot be applied retroactively.

2. The Components of the PCIA Revenue Requirements Originate in Policy-Heavy Ratesetting Proceedings

True ratemaking can also be seen in the components of the PCIA rates themselves. The costs making up the PCIA revenue requirement are imbued with policy considerations and originate in policy-heavy proceedings such as the utility rate cases, and the IRP, RA, RPS proceedings. In *Edison*, the Court noted that, contrary to the rates set through a general ratesetting proceeding, the fuel clause rates did not apply to rates for which the utility would earn a return, but rather to expenses recovered

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42 *Id.,* at 13-16.

43 Scoping Ruling, at 2-3.

44 D.19-10-001, at Ordering Paragraph (O¶) 3.

45 *Edison,* 20 Cal.3d at 829 (citing *City of Los Angeles,* 15 Cal.3d at 697).

46 *Ibid*.

on a dollar-for-dollar basis.[47] Likewise, the Commission has since stated that "in determining whether the rule against retroactive ratemaking applied in a particular situation, it is necessary to determine the origin of the rates underlying the refunds being challenged."[48]

As shown in Figure 2 of CalCCA's Opening Comments, the PCIA is set by comparing the IOUs' portfolio costs with its portfolio value.[49] The contents of those portfolios all originate in important ratesetting proceedings. UOG costs—which, unlike fuel clauses, include a return on equity for undepreciated capital—originate in the IOUs' GRCs. The rest of the PCIA-eligible portfolio derives from procurement mandates established in weighty ratesetting proceedings like the IRP, RA, and RPS cases. Unlike dollar-for-dollar fuel expenses, the revenue requirements underlying the costs recovered in the PCIA originate in what might be called the heavyweight class of California's ratesetting proceedings.

That is why, when discussing SCE and PG&E's 2025 ERRA Forecast cases, the Joint IOUs' attempt in Reply Comments to draw a parallel between fuel clause adjustments and the PCIA falls short.[50] The Joint IOUs argue that "pass-through costs implicated by the MPB proposals are generation costs subject to pass-through ratemaking," and distinct from "Energy Supply Administration costs originating in a [GRC]."[51] This argument ignores both the substantial policy implications of the RA MPB proposals in this proceeding and the origin of the IOUs' generation costs in general rate cases and other important ratesetting proceedings.[52] Stated another way, the Commission does not, as the Joint IOUs' argument implies, have *carte blanche* to revise any rate retroactively simply because the rate implicates "pass-through costs." The nature of the costs is a factor in *Edison*, but it is not determinative.

That is not to say each time the IOUs true-up and retroactively change PCIA rates in the ERRA Forecast proceedings the Commission has conducted prohibited retroactive ratemaking. Without a change in methodology based on broad policy considerations, the true-up is not general ratemaking. In *Edison*, the Court emphasized the simple nature of the fuel clause adjustment at issue and its attendant

47 *Id.* at 818-819.
48 D.12-03-026, at *30 (citing *Ponderosa*) (emphasis added).
49 CalCCA Opening Comments, at 12, Fig. 2.
50 Joint IOUs' Reply, at 10-11.
51 *Id.* at 11, n. 28.
52 That is not to say that general ratemaking can only take place in a GRC. *See, e.g., Ponderosa*, 197 Cal.App.4th at 63-64 (finding that a Commission decision in an 11-utility ratesetting proceeding impermissibly revised a ratesetting formula set in a rulemaking proceeding).

advice letter process;[53] and most of the time "the only business at hand" in the ERRA Forecast proceedings is "the application of a mathematical formula to a figure definitively established by reference to the utilities books."[54] Such mechanics are the sometimes-missed intention of PCIA ratemaking in the ERRA Forecast proceedings: to simply plug verifiable amounts into existing equations to set rates aimed at achieving indifference. However, the Commission runs afoul of the prohibition against retroactive ratemaking when it *revises* a ratemaking formula based on policy considerations *and then* applies that new ratemaking formula retroactively. The fact some of the costs in the PCIA can be labeled pass-through costs is not determinative: *it is the policymaking* that is the first hallmark of "true ratesetting."

3. The Impacts of the Retroactive Rates Will Be Significant and Would Not Have Occurred in Due Course

Another hallmark is the impact on LSEs and customers that would not have otherwise occurred. The courts and the Commission have been reluctant to find prohibited retroactive ratemaking has taken place when the retroactive rates have little impact. In *Edison*, the Court emphasized how using recorded actuals to calculate the refund was simply another way of balancing overcollections or undercollections for fuel costs that would have naturally occurred under the weather averaging method used in the original methodology.[55] As a result, the Court determined, the Commission's order left the utility no worse and no better off than it would have been had the Commission not ordered the refunds.[56] Similarly, the Commission has been reluctant to find prohibited retroactive ratemaking when a revised rate has no real impact compared to an existing rate.[57]

While *Edison* did not result in the "disruptive financial consequences of true retroactive ratemaking,"[58] the same cannot be said for the CCAs and departed customers if the Commission retroactively applies a revised RA MPB. The reason is, in part, due to the difference between market

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53 *Edison,* 20 Cal.3d at 821, 829.

54 *Id.* at 829 (citing *City of Los Angeles,* 15 Cal. 3d 680) (emphasis added).

55 *Id.* at 824-827.

56 *Id.* at 824-826 (stating "Inasmuch as the two methods achieve the identical result -- a final balancing of fuel clause over- and undercollections -- and Edison itself embraces the former, the commission rightly concluded that it has not subjected Edison to retroactive ratemaking by choosing the latter because of a perceived need to institute the new energy clause without delay.").

57 *See* 1982 Cal. PUC LEXIS 1270 (Apr. 28, 1982) (No Original Decision Number) (concluding that including past franchise fees in the utility's rate adjustment did not constitute retroactive ratemaking because the revised practice would not have produced a different result from the existing practice); *see also* D.04-03-041, 2004 Cal. PUC LEXIS 80, *15 (Mar. 17, 2004) (rejecting challenges to a revision to the procedures for recovering expenses from water balancing accounts because they had no direct or indirect effect on rates).

58 *Edison,* 20 Cal.3d at 824-826.

costs and market values, and the proxy nature of the RA MPB. In *Edison*, the Court relied heavily on both the mathematical nature of the refunds and the fact they were calculated based on "empirical data" and figures "definitively established by reference to the utilities' books."[59] In other words, no complicated formula or methodology was needed to calculate what the actual costs of fuel were: they were what the IOUs paid, as entered in their accounting books.

Here, however, the Commission must wrestle with the more nebulous concept of the "portfolio value" of capacity, a concept that is not definitively set in, and cannot be solely derived from, the IOUs' accounting books. Instead, capacity portfolio value relies on the RA MPB, an administratively determined proxy used to assess the value of capacity within the IOUs' portfolios.[60] Since this proceeding aims to revise the RA MPB itself, the Commission will not simply be comparing forecasted capacity value to actual capacity value; it will be revising what constitutes actual capacity value. And that is a contentious issue: some parties have argued the capacity value of the IOUs' portfolio is best measured via the short-term market value at which RA can be sold today;[61] and others have suggested that older market transactions from five, ten or twenty years best reflect the capacity value of an IOU's portfolio.[62] Thus, unlike in *Edison*, the "truth" of the true-up *itself* is in dispute. No clear, easily verifiable actual market values exist to compare to the forecasted portfolio values.

Because portfolio market value is a subjective value, the shift in PCIA rates that will come from using a revised RA MPB would not have occurred naturally, as a matter of course, over time. When truing up an apple with an orange, it is not possible for the orange to be the natural evolution of the apple. That is, unlike in *Edison*, a new RA MPB methodology cannot naturally leave CCAs and customers in the same place the old RA MPB would have left them.

This reasoning in *Edison* also supports a finding of retroactive ratemaking here even though the Commission implicitly found none in D.19-02-023.[63] There, the Commission ordered PG&E to

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59 *Id.* at 828-829.

60 D.19-10-001, at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year.").

61 *See* CalCCA Opening Comments, at 25-31; CalCCA Reply, at 15-18; DACC/AReM Opening Comments at 3-5; DACC/AReM Reply at 4; Shell Reply, at 5-6; CLECA Reply, at 4.

62 *See* Joint IOU Opening Comments, at 15-18; Joint IOU Reply, at 11-16; TURN Opening Comments, at 1-3.

63 D.19-02-023, at 26. Note that the Commission's decision does not expressly address the legal question of retroactive ratemaking. Most of the debate in this proceeding surrounded what the Commission ordered in D.18-10-019 and not whether that order was retroactive ratemaking.

calculate 2019 PCIA rates by "replacing the forecasted 2018 brown power benchmark in the 2018 Forecast ERRA case by applying actual 2018 market prices to actual PCIA-eligible generation deliveries"[64] That is, similar to *Edison*, PG&E was required to use the actual, verifiable energy value of its portfolio, as demonstrated by the CAISO market, to true-up the forecasted energy value of its portfolio. No similar actual value exists for capacity.

The forced change to rates contemplated in this case will also have a substantial impact on customers and LSEs. The Staff Report models the extensive impact on the RA MPB of each of its proposals, which, all other things equal, will significantly increase rates for CCA customers.[65] Such increases do not come without consequences. One of the reasons for the policy against retroactive ratemaking is to avoid surprises in the cost of electricity for customers. The Joint IOUs ignore departed customers to discuss affordability concerns for bundled customers,[66] but this argument not only disregards affordability impacts for unbundled customers from higher PCIA rates tied to a revised RA MPB, it ignores the reality of recent increases in RA prices, which should have the impact of lowering those rates. In addition, higher PCIA rates from a revised RA MPB can negatively impact CCA revenues when customers opt out or CCAs draw down reserves to reduce rates. These substantial impacts – to both customers and CCAs – are distinguishable from the refunds in *Edison* that left SCE no better or worse off than it would have been.

C. Policy Weighs in Favor of Applying the New Methodology Only Going Forward

Much has changed since *Edison* suggested the Commission avoid applying a revised RA MPB methodology to true up 2025 rates. *Edison* was decided fifty years ago when the California utilities were vertically integrated, when the concept of departed customers did not exist, and when retroactive ratemaking was a shareholder versus ratepayer issue, not a ratepayer versus ratepayer issue like in the instant proceeding. The Court and the Commission in *Edison* sought to mitigate a clear and easy-to-calculate windfall for a large corporation, earned on the backs of ratepayers already suffering from high gas prices, because doing so was fair and reasonable.[67]

Here, while some degree of revision to the RA MPB may be helpful to increase volumes and ensure market-relevant data are used going forward, questions of fairness and reasonableness are much

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64 *Id.* at 21.
65 Staff Report, at 13-18.
66 Joint IOU Reply, at 3 (quoting TURN Opening Comments, at 1).
67 *See Edison,* 20 Cal.3d at 816-817, 824 ("Seen thus in its full perspective, the transitional procedure adopted by the commission to deal with these overcollections is surely 'fair and reasonable.'").

in dispute. Such questions arose during the prehearing conference with regard to retroactivity when ALJ Rambo, using an analogy of football referees changing how they apply the rules at halftime in order to address an odd formation or a trick play, asked: If the Commission is applying the law on indifference incorrectly, shouldn't it change that application during the true-up, *i.e.*, at halftime, to ensure indifference?[68] The answer is two-fold. First, in changing the RA MPB at halftime of the indifference calculation, the Commission would be changing the rules themselves as opposed to the application of those rules. Second, especially in the case of rates set in SCE's 2025 ERRA Forecast rates, the Commission has already acted to mitigate potential unfairness resulting from the 2025 Forecast RA MPB. These concepts are addressed below.

1. Applying the RA MPB Retroactively Changes the Rules at Halftime of the Indifference Calculation, Not Just How Those Rules are Applied

While indifference is the law of the land, the rules established in D.18-10-019 and D.19-10-001 determine how the law is implemented. OP 3 of D.19-10-001 sets the rule that must be followed for the true-up – requiring ED to true up the RA MPB based on the "volume-weighted average of all IOU, CCA and ESP RA-only market transactions," as listed in Table II of Attachment A to that decision.[69] Revising those ordering paragraphs set in Rulemaking 17-06-026 is, quite literally, changing the rules. That situation is different than applying the same, existing rules to new facts.

Applied to the football analogy, while the referees may change how they apply the rules when they encounter the second, future iteration of a novel situation in a game, they cannot change the rules themselves; and then go back and unwind plays that have already happened based on those new rules. Consider the National Football League's (NFL's) current consideration of a ban on the play colloquially called the "Tush Push"; where members of the offensive team will push the quarterback (or other ball carrier) from behind and into the end zone, or across the line to gain. The NFL is currently in the process of what aptly may be called a rulemaking, like the instant one, to consider whether to adopt this ban – a small change in the rules that would only apply to a fraction of game circumstances. That change is left up to the NFL Rules Committee (not the referees), and such changes would only be applied to future games, rather than, for example, declaring new winners and losers to games played in the 2024 season based on an elimination of touchdowns scored via the Tush Push. Indeed, such a result would be the NFL's version of impermissible retroactive ratemaking.

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68 R.25-02-005, 1 Tr. 70:23-71:24 (Administrative Law Judge Rambo).

69 D.19-10-001, O¶ 3(c), (d).

Here, changing at halftime these impactful rules, to which LSEs have designed and managed rates and customers expect their bills to be based on those rates, is different than applying the same rule to new facts and has significant impacts on customers and LSEs.

2. The Commission Has Already Set Rates to Mitigate the 2025 RA MPB

ALJ Rambo is right to focus on the Commission's duty to ensure indifference, but utilizing the current RA MPB methodology to true up 2025 rates would not shirk that duty. In fact, the Commission already addressed questions of indifference in setting the 2025 PCIA rates. In all three of the 2025 ERRA Forecast cases, the Commission issued rulings requesting procedural mechanisms tied to potential undercollections on account of the RA MPB potentially being overstated. [70] In response, in D.24-12-039, the Commission approved rates based on SCE's Alternate October Update,[71] which included a proposal to recategorize almost half of SCE's PCIA-eligible capacity portfolio from System and Flexible RA and Flexible RA to Local RA (RA Recategorization Proposal).[72] The Commission adopted the RA Recategorization Proposal not only for the 2025 forecasted indifference amount, but also for the 2024 true-up, shifting $335.8 million in benefits to SCE's bundled customers on the backs of departed customers.[73] The result was SCE counting 4,500 megawatts (MW) as Retained *Local* RA - capacity all parties to the proceeding agreed was used as *System* RA during 2024 and forecasted to be used as *System* RA in 2025.[74] The Commission presumably allowed this exception to its prohibition on policymaking in the ERRA proceedings because it considered the Local RA MPB to be a better proxy for the value of RA in SCE's service territory. If so, the Commission has already addressed the question of overstated System RA MPBs in SCE's territory.

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70 A.24-05-007, *E-Mail Ruling Requesting Party Comment on Procedural Mechanisms* (Oct. 8, 2024); A.24-05-009, *E-Mail Ruling Requesting Party Comments on Procedural Mechanisms* (Oct. 8, 2024); A.24-05-010, *E-Mail Ruling Requesting Party Comment on Procedural Mechanisms* (Oct. 8, 2024). Note that in the Diablo Canyon Forecast proceeding, the RA MPB is a question of the cost of replacement capacity and would not be an issue driving the difference in rates between bundled and unbundled customers, but rather the difference in rates between customers in PG&E's service territory and customers outside of its service territory.

71 A.24-05-007, Exh. SCE-09.

72 *Ibid.* at 2:5-7 (explaining how SCE's AOU changes "how SCE applies System, Flexible, and Local RA MPBs to its PCIA portfolio *for both its 2024 true-up* and its 2025 forecast") (emphasis added).

73 *Ibid.* (explaining how SCE's AOU changes "how SCE applies System, Flexible, and Local RA MPBs to its PCIA portfolio *for both its 2024 true-up* and its 2025 forecast") (emphasis added).

74 *See* A.24-05-007, *CalCCA's Comments on Proposed Decision* (Dec. 2, 2024), at 2.

Further, the Commission calculated the 2025 PCIA rates for PG&E and SDG&E based on this same methodology.[75] That is, despite its own observation that "[t]here is currently no policy or rule governing the methodology for assigning capacity to RA subcategories for the purpose of valuation," the Commission valued thousands of MW of capacity that was used as System RA capacity as Local RA capacity across *all three* service territories. Assuming all RA valued as Local RA should have been valued as System RA, *i.e.*, based on its actual, higher value use, the current 2025 PCIA rates *already include over $1 billion in mitigation measur*es for inflated System RA MPBs.[76] Applying a new RA MPB to 2025 PCIA rates is unnecessary to ensure indifference, and it sets rates that are the product of "general ratemaking" retroactively, in violation of the law. As a result, the Commission should only apply a new RA MPB calculation methodology prospectively.

III. THE COMMISSION MUST ENSURE ITS TRACK ONE FINDINGS ARE BASED ON SUBSTANTIAL EVIDENCE AS REQUIRED BY SECTION 1757

In any Track One Decision, the Commission should not proceed until its findings are supported by "substantial evidence" as required by Public Utilities Code section 1757. CalCCA has previously urged the Commission to ensure transparency and adequate data and modeling to allow the rate impacts for all customers to be calculated.[77] In addition, to the extent the Commission moves forward with modifying the RA MPB, it must support its identification of the problem it seeks to solve, as well as the solution, with substantial evidence. As set forth in detail below, the Commission should proceed cautiously and seek a narrowly tailored solution given that: (1) the Commission's Track One decision must be supported by substantial evidence; (2) the Joint IOU's assertion that CalCCA's insistence on evidence to support a Track One Decision is somehow "results-oriented" or "irrelevant" should be rejected; (3) while the Staff Report is focused overall on accuracy of the MPB, its primary focus is to solve the reduced transaction volume to calculate the RA MPB; and (4) certain data presented in the Staff Report does not rise to the level of substantial evidence needed to support the Commission's adoption of many of the Staff Proposals to address the underlying reduced volume problem.

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[75] A.24-05-007, Exh. SCE-09, at 135-136 ("As described in Section I.B., in this Alternate October Update, SCE is applying the RA MPBs based on the type of RA product provided by the underlying PCIA-eligible resource… This application of the RA MPBs aligns with how the RA MPBs are calculated by ED using reported purchase and sale prices of transactions made by LSEs. *This application also aligns with how PG&E and SDG&E apply the RA MPBs for purposes of PCIA ratemaking*") (emphasis added).

[76] For PG&E the total impact is $990.0 million, of which departed load's share would be $530.6 million. For SDG&E the total impact would be $253.9 million, with departed load's share being $185.4 million.

[77] *See* CalCCA Opening Comments, at 25; CalCCA Reply Comments, at 14-15.

A. Public Utilities Code Section 1757 Requires the Commission to Support its Findings with Substantial Evidence

Public Utilities Code section 1757 requires the Commission to support its ratesetting decisions with findings, and to support those findings with "substantial evidence in light of the whole record."[78] "On matters related to substantial evidence, the operative inquiry is whether the contested findings or conclusions are reasonable."[79] In other words, would a reasonable person make the same conclusion based on the evidence?[80]

Here, the Track One record only includes the Staff Proposal and party comments. Commission findings to support any Track One "fix" to the RA MPB calculation will need to include findings that a problem exists, and if so, that one or more of the Staff Proposals can "fix" the problem. While the Commission has identified overall concerns to be addressed in the rulemaking, [81] the Track One scope is only focused on potentially recalculating the RA MPB on an interim basis.[82] As the Staff Report presents the only data upon which the Track One Decision can be based, the reasonableness of any Commission Track One findings adopting one or more Staff Proposals needs to be determined based on the evidence presented in the Staff Report.

As set forth below, the only problem identified that can be supported with substantial evidence is a drop in transaction volume for calculating the 2025 RA MPB. In addition, the evidence presented for the Staff Proposals to "fix" the volume problem is based on non-transparent and limited data in the Staff Report. While CalCCA acknowledges that some of the data held by Energy Division is confidential and cannot be openly shared, the data that *is* provided does not rise to the level of

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78 Section 1757(a) (standard of review of Commission decisions in ratemaking proceedings of specific application addressed to particular parties); OIR, at 27 (listing the "Respondents" to the OIR as PG&E, SCE, SDG&E, all CCAs, and all ESPs); Scoping Ruling, at 4 ("This ruling confirms the Commission's preliminary determination [in the OIR] that this is a ratesetting proceeding"). To the extent the Commission determines the evidentiary standard for this ratesetting proceeding is governed instead by Section 1757.1, the Commission still must base its decision on findings supported by the record, not "abuse its discretion," and "proceed[] in the manner required by law." Pub. Util. Code § 1757.1(a).

79 D.99-06-095, *In re Pacific Gas and Elec. Co.* (June 24, 1999), at 2; *see also Independent Energy Producers Ass'n/Utility Reform Network v. Pub. Util. Comm'n* (2014) 223 Cal.App.4th 945 (uncorroborated hearsay . . . does not constitute "substantial evidence in light of the whole record").

80 *See Securus Technologies, LLC v. Pub. Util. Comm'n* (2023) 88 Cal.App.5th 787, 802 (a party seeking to overturn a Commission finding for lacking the support of substantial evidence must demonstrate that based on the evidence before the Commission, "a reasonable person could not reach the same conclusion").

81 *See* OIR, at 13-14; *see also id.* at 15 ("The issues to be addressed in this rulemaking result from more fundamental market changes, and from repeated or consistently arising problems or opportunities").

82 *See* Scoping Ruling, at 3 (describing the narrow options to consider in Track 1 to recalculate the RA MPB based on the Track 1 Proposals).

"substantial evidence" needed to support the Commission's adoption of many of the Staff Proposals. Other parties, including Cal Advocates,[83] CUE,[84] Shell,[85] and CLECA[86] have all noted that the data provided in the Staff Proposal is thin. The Commission should proceed cautiously and adopt the most narrowly tailored solution to fix the reduced volume problem in Track One. The Commission can then proceed to a more comprehensive examination of the PCIA methodology in Track Two.

B. The Joint IOU's Assertion that CalCCA's Insistence on Evidence to Support a Decision is Somehow "Results-oriented" or "Irrelevant" Should be Rejected

The Joint IOUs' assert that CalCCA is "attempt[ing] to unnecessarily delay immediate and necessary reforms to the PCIA" and "placing results-oriented barriers in front of the Commission" "produc[ing] a Proposed Decision on the appropriately expedited timeline for Track 1."[87] To the contrary, CalCCA has sought modeling, along with transparent and error-free data, to understand the rate impacts of each Staff Proposal on bundled and unbundled customers, within the Commission's suggested timelines.[88] Not only is it questionable whether the Staff Report amounts to substantial evidence under section 1757, the rush to judgment that something is "wrong" with the RA MPB, or any other component of the PCIA methodology, is based on current market conditions, which are constantly in flux. There is evidence of a high RA MPB, which reflects the high prices in the RA market in recent years and a declining volume. The Commission should tread cautiously in making a major policy change in response to a temporary market swing.

The Joint IOUs are concerned that additional data, modeling, or process "are not needed for Track 1" and "will strain the Commission's ability to produce a Proposed Decision on the

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83 *See* Cal Advocates Reply, at 6 ("All parties would benefit from a more complete picture of transaction data to inform their evaluations of proposals, consider how to implement or modify such proposals, or provide alternative proposals.").

84 *See* CUE Reply, at 8 (considering Proposal One, and stating that "[h]ow far back one should go over time to reflect a ratably procured portfolio is one that the Joint IOUs do not answer. . . To determine the appropriate timeframe, it would be useful to have evidence from the IOUs' procurement and risk management practices.").

85 *See* Shell Reply, at 6 ("[A]dditional fact-gathering and analysis is necessary to develop an understanding of all of the drivers and implications of any change to ensure the PCIA remains a tool for *assuring customer indifference.*") (emphasis in original).

86 *See* CLECA Reply, at 3 (recommending "a light touch, "no regrets" approach to Track 1 with a focus on data quality, while deferring major policy changes to Track 2 to allow for more fulsome consideration. The Commission should avoid changing longstanding policy to address concern about short-term outcomes without adequate process and consideration").

87 IOU Reply, at 2.

88 *See* CalCCA Opening Comments at 25; CalCCA Reply, at 14-15.

appropriately expedited timeline for Track 1."[89] The goal here, however, should not be facilitating a rushed, opaquely supported Commission Decision. Instead, if the Commission implements an expedited change to the RA MPB based on concerns over the potential impacts to bundled customers as proposed in the Staff Report, it is required to issue findings regarding the problem, and any solutions, based on "substantial evidence." CalCCA's and other parties' insistence that this statutory standard be met is in no way "results-oriented" or "irrelevant."

C. The Only Finding on the Identified Underlying Problem with the RA MPB that Can be Supported with Substantial Evidence is a Reduction in Transaction Volume for the 2025 Forecast MPB

The OIR, Section 3.1.1, identifies "staff proposals for resolving Track One," which are also referenced in the preliminary scope: "[a] preliminary focus on the RA MPB is expected due to specific data concerns raised by ED staff regarding the RA MPB issued in October 2024."[90] The Staff Report was then issued after the OIR, providing additional detail regarding the ED staff "data concerns." In the Staff Report, the ***only*** verified "problem" identified is the "significant drop in transaction volume" that ED identified while calculating the 2025 Forecast MPB. Figures 3 and 4 in the Staff Report demonstrate the drop in transaction volume referred to by ED (*i.e.,* System RA transactions 2022-2025 MPB Forecast: (1) 2022 MPB Forecast, 21,438; (2) 2023 MPB Forecast, 26,594 MW; (3) 2024 MPB Forecast, 52,000 MW; (4) 2025 MPB Forecast, 6,705 MW).[91] All of the other identified problems – *e.g.,* "a recent subset of RA transactions that ***may*** be driven by market power," "an array of issues that ***could*** result in RA MPB divergence relative to the entire portfolio value," and "the current methodology fails to exclude non-market or non-arm's length transactions that ***may not*** reflect genuine market prices"—are speculative and not adequately supported by data.[92]

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89 Joint IOUs Reply, at 2-3.

90 OIR, at 24.

91 Staff Report, Fig. 3 at 6. Note that neither Energy Division nor the Commission have demonstrated what volume of transactions is necessary to ensure a robust RA MPB. In fact, the record should include an analysis of what the necessary volume should be. For example, a statistical power analysis could be performed to demonstrate what error bounds on the MPB metric would be material to ratepayers, and therefore what the required volume of transactions should be. For purposes of this brief, we assume that transaction volumes within the range of previous years, which were accepted by Energy Division as reasonable, would also be deemed reasonable for calculating the current MPB.

92 *See, e.g.,* Staff Report, at 3-7 ("[R]apid increases in prices for certain market transactions have revealed issues inherent to the methodology that ***may*** be undermining customer cost indifference") (emphasis added); *see also id.* at 5 (the current RA price "is reflective of a recent subset of RA transactions that ***may*** be driven by market power, as it ***does not appear*** that new RA projects are or would be this expensive") (emphasis added); *see also id.* at 7 ("ED has identified an array of issues that ***could*** result in RA MPB divergence relative to the

Given the limited evidence supporting the various problems listed both in the OIR and the Staff Proposal, in Track One the Commission should only focus on the reduced volumes.[93] The next question from an evidentiary standpoint is whether a finding adopting any of the Staff Proposals to fix the reduced volumes can be supported by substantial evidence, which is addressed in the following section.

D. Certain Data Presented in the Staff Report Do Not Rise to the Level of Substantial Evidence Needed to Support the Commission's Adoption of Many of the Staff Proposals to Address an Underlying Volume Problem

Parts of the data presented in the Staff Report to address ED's concerns, including the reduced volume problem, are non-transparent, limited, and by Energy Division's admission not validated. For example, Section 4 of the Staff Report includes the "analysis of the options presented in" the OIR:

> [C]ompar[ing] the MPB calculations using the current methodology with the MPB calculations (for the same time periods) using the proposed methodologies as follows: using all available transaction data (Proposal One), creating a monthly MPB value (Proposal Four), and creating a combined RA MPB (Proposal Five). ED provides these figures so stakeholders can see the impacts of applying the methodological reforms as compared to the current methodology.[94]

Notably, ED openly admits the lack of validation of this data by stating:

> It should be noted that these values are <u>*solely for illustrative purposes*</u> and <u>*largely correct*</u> but would be subject to further <u>*data cleaning and verification*</u> if these proposals were to be adopted for future years.[95]

Why the figures for 2026, which are proposed to be adopted in Track 1, which are described as only "largely correct," will not be subject to the same data cleaning and verification is unclear. In addition, ED states that it "does not currently have the necessary data to exclude swap, sleeve, or affiliate transactions, and therefore the potential impacts from Proposals Two and Three are not modeled below."[96] ED has therefore admitted that the data, which it is requesting the Commission rely on to

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entire portfolio value" and "The current methodology fails to capture all transactions for deliverability in year n and fails to exclude non-market or non-arm's length transactions that <u>***may not***</u> reflect genuine market prices") (emphasis added); *id.* at 8 ("[t]he bucketing system therefore <u>***may not***</u> accurately capture all costs associated with all contracts for deliverability in a specific year"); *id.* at 9 ("[u]ncertainty related to implementation of the Slice of Day (SOD) framework . . . . <u>***could be***</u> driving some of the sharply reduced liquidity") (emphasis added).

93 To the extent the Commission can define and identify other non-market transactions, including swap, sleeve, and affiliate transactions, CalCCA supports excluding those to ensure accuracy.

94 Staff Report, at 12.

95 *Id.*, at 12 (emphasis added).

96 *Ibid.* While CalCCA supports excluding such transactions to the extent they can be defined and identified, it questions how ED will do so if it has no data to identify them.

make findings adopting any of the Staff Proposals, is not validated and omits information.[97] The Commission must rely on "substantial evidence" that any proposal it adopts will "fix" the problem of reduced volumes. Given the limitations in the data underlying the Staff Proposal, the Commission should cautiously proceed with a narrowly tailored solution to fix this problem.

IV. ANY TRACK ONE "FIX" SHOULD BE NARROWLY TAILORED TO ADDRESS ONLY THE TRANSACTION VOLUME "PROBLEM"

Any Track One "fix" adopted by the Commission should be narrowly tailored to fix the only identified "problem" of reduced transaction volume. As noted in CalCCA's Opening and Reply Comments on the OIR, Proposals Two through Five are distinguishable from Proposal One in that they do not upend the "mark-to-market" methodology established by the Commission to value the benefits retained by bundled customers. Instead, Proposals Two through Five utilize the existing methodology, but tweak the inputs to remedy the reduced volume problem and ensure only market-based transactions are included. Given the data issues described in Section III., above, however, the Commission must tread carefully and adopt a narrowly tailored solution that only uses validated and transparent data to ensure its decision is based on substantial evidence. As stated below, the Commission should: (1) adopt the Proposal Five combination of MPBs which should increase the volume of mark-to-market transactions to allow it to stop there, and proceed to a full evaluation of the PCIA methodology in Track Two; and (2) reject Proposal One upending the RA MPB methodology. If after implementing Proposal Five the Commission still decides it must broaden the timeframe of transactions to include in the calculation, it should limit the timeframe as narrowly as possible.

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[97] In addition, several errors and/or mislabeled information in the Staff Proposal should be noted, which raises the suspicion of other undiscovered errors in the ED calculations. For example, Figures 8 and 9 include misleading and mislabeled information, especially when compared to Figure 7. Both Figures 8 and 9 provide the "Current 2024 Final MPB $kw/Month (as a combined value), but include a footnote noting that labeling the combined 2024 Final MPB as "Current" is incorrect, as they represent "two years less of transaction data for local RA" which uses almost four years of data. *See* Staff Report, n. 11-12, at 15. This number is then compared to a "Proposed 2025 Forecast MPB Using Combined System, Flex, Local RA Data from 2020-2024 (Proposal 2)." However, this figure as mislabeled as Proposal 2 is simply the combined System, Flex, and Local RA Data under the current methodology (i.e., as noted in Footnote 9 and 10 (referencing the different time periods utilized for calculating the Local RA MPB versus the System and Flex RA MPB)) Although not stated on Figures 8 and 9, adding information from 2020-2024 would likely also implicate Proposal One. The result of this mislabeled information is substantial confusion as Figure 7 provides the "Current 2025 Forecast MPB $kW/Month as $13.71 (rather than the $19.01 and $28.94 depicted in Figures 8 and 9).

A. If Proposal Five's Combination of MPBs Results in an Accurate and Robust RA MPB for 2025, the Commission Should Stop There in Track One and Proceed to its Full Evaluation of the PCIA Methodology in Track Two

The Commission should implement the combination of MPBs as set forth in Proposal Five of the OIR, and stop there in Track One and proceed to a full evaluation of the PCIA methodology in Track Two. The combination of MPBs will likely go a long way towards fixing the transaction volume problem. If the combined MPBs meet an acceptable volume level to establish a robust MPB, the Commission will be able to implement this narrowly tailored solution to fix the reduced volume problem to ensure a robust RA MPB.[98]

B. Proposal One Upending the RA MPB Methodology in Track One Should be Rejected or in the Alternative, Limited

CalCCA provides extensive support for its recommendation that the Commission reject Proposal One outright given its inconsistency with the current mark-to-market framework which fairly values the benefits remaining with bundled customers as current market value.[99] In fact, the Joint IOUs' insistence that the value of benefits must equate to the IOU procurement costs is simply based on a faulty premise, although the IOUs repeatedly state it as if it were the current rule (which it is not). In any event, to the extent the Commission finds that Proposal Five does not increase volumes to an acceptable level to calculate a robust RA MPB, the Commission could adopt a limited version of Proposal One, broadening the timeframe only up to what is necessary to reach the acceptable volume.

1. The Joint IOUs' and TURN's Arguments in Support of Proposal One are Based on the Faulty Premise that the Value of Benefits Remaining with Bundled Service Customers Must Equate to the Procurement Costs of the IOU PCIA-eligible Portfolios

The Joint IOUs' and TURN's arguments in support of Proposal One are based on the faulty premise that the value of benefits remaining with bundled service customers <u>*must*</u> equate to the procurement cost of all capacity from the IOU PCIA-eligible portfolios deliverable for a given year. In fact, the Joint IOUs employ a technique throughout their Opening and Reply Comments in which they repeat this premise repeatedly, apparently hoping that the more they say it, the higher likelihood of the Commission believing it to be true.[100] However many times the IOUs repeat it, though, the IOUs' new test does not comport with the mark to market methodology at the heart of the Commission's RA MPB

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98 *See* Staff Report, at 7, Fig. 4.
99 *See* CalCCA Opening Comments, at 25-31; CalCCA Reply, at 15-18.
100 *See* IOU Reply, at 12.

methodology. In other words, the value reflected in the RA MPB is not what the IOUs originally paid for the capacity, but rather what those resources can be bought or sold for *today*.[101] To the extent the IOUs are limited by their Bundled Procurement Plans (BPPs) to take advantage of current market prices by selling the RA, the Commission should address those BPP limitations to ensure optimization of the PCIA portfolios, rather than changing the PCIA methodology to favor bundled customers.[102]

2. To the extent the Commission Must Incorporate Additional RA Transactions to Solve its Reduced Volume Problem, Party Proposals to Limit the Timeframe for Those Transactions Should be Adopted

If after implementing Proposal Five combining the System, Flex, and Local RA transactions, the Commission remains concerned about the transaction volumes, the Commission should very narrowly increase the timeframe to ensure the calculation remains as close to current market value as possible. CalCCA recommends in its OIR Reply Comments that if the Commission adopts Proposal One it should limit the timeframe of transactions to the most recent three years of data (for delivery in the fourth year) consistent with DACC/AReM's compromise position.[103] The Commission could limit the timeframe even more to ensure it stays as close to the current market value as possible, which CalCCA supports.

V. THE JOINT IOUS' CONTINUED INSISTENCE THAT A CHANGE TO THE PCIA METHODOLOGY INCREASES AFFORDABILITY DISINGENUOUSLY DENIES THAT THE PCIA METHODOLOGY IS ZERO SUM

Curiously, the Joint IOUs state that CalCCA errs in its argument that the PCIA and ERRA processes do not impact affordability to *all* customers. The Joint IOUs claim that the existing PCIA methodology "creates artificial costs" borne by bundled service customers by valuing RA in the PCIA-portfolios at the current market price rather than at the price the IOUs originally paid for it.[104] The Joint IOUs advance this argument now, despite not raising the same argument when portfolio costs exceeded market costs, thereby favoring bundled customers. Almost all parties recognize the PCIA methodology as "zero-sum," only impacting affordability for one sector of customers while the other sector benefits through the PCIA allocation.[105] The Joint IOUs' argument once again fails to recognize

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[101] *See* CalCCA Opening Comments at 25-31; CalCCA Reply, at 15-18.

[102] *See* CalCCA Reply, at 10-13.

[103] *Id.* at 20-21.

[104] IOU Reply, at 3-5.

[105] *See* CUE Opening Comments, at 1 ("The PCIA is . . . a zero-sum situation in which, if the amount of the charge is not correct, one side gains at the cost to the other"); Cal Advocates' Reply, at 6 ("Cal Advocates agrees with CUE's observation that "the PCIA is thus a zero-sum situation in which, if the amount of the charge

that Section 366.2(g) allows unbundled customers to receive the current *value* of benefits. And once again, if the IOUs are restrained by their BPPs from benefitting from selling their RA in the current market, the change should be made to their BPPs, rather than the PCIA.

VI. CONCLUSION

CalCCA respectfully requests the Commission adopt the recommendations set forth herein.

Respectfully submitted,

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April 21, 2025

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is not correct, one side gains at the cost to the other"); Shell Reply, at 3 (citing Pub. Util. Code § 365.2) ("Relying on the PCIA to improve affordability for one class of customers (*e.g.,* bundled) would result in decreased affordability for another (*e.g.,* unbundled customers). More concerning, the results-oriented objective would *not* result in indifference – contrary to legislative mandate.") (emphasis in original); CLECA Reply, at 3 ("CLECA's perspective includes both bundled and unbundled customers, and CLECA agrees with [CalCCA] that affordability concerns apply to all customers").

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 RESPONSE TO SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PETITION FOR MODIFICATION OF DECISIONS 23-02-040 AND 24-02-047

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April 21, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA[1] recommends that the Commission:

- Adopt SCE's PfM to modify bridging requirements for generic and LLT procurement requirements;
- Extend the modified bridging requirements to DCR procurement requirements; and
- Clarify the PfM's applicability such that an LSE with an executed long-term contract that was terminated for circumstances outside the LSE's control and that the LSE is making good faith efforts to replace can also utilize the modified bridge requirements.

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1 Acronyms used in this Summary of Recommendations are defined in the body of this Response.

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 RESPONSE TO SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PETITION FOR MODIFICATION OF DECISIONS 23-02-040 AND 24-02-047

California Community Choice Association[2] (CalCCA) hereby submits this Response to *Southern California Edison Company's (U 338-E) Petition for Modification of Decisions 23-02-040 and 24-02-047*[3] (PfM) pursuant to Rule 16.4(f) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure.[4] Southern California Edison Company (SCE) requests that the Commission modify Decision (D.) 23-02-040[5] and

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

3 *Southern California Edison Company's (U 338-E) Petition for Modification of Decisions 23-02-040 and 24-02-047*, Rulemaking (R.) 20-05-003 (Mar. 21, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M559/K371/559371562.PDF.

4 *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.

5 Decision (D.) 23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios To California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 23, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

D.24-02-047[6] to change the mid-term reliability (MTR) bridge requirements in the lower demand non-Q3 months of October through June for the generic capacity and long lead-time (LLT) procurement requirements for LSEs that meet their month-ahead system RA requirement in those months.

I. INTRODUCTION

D.21-06-035[7] and D.23-02-040[8] order load-serving entities (LSE) to procure 15,500 megawatts (MW) of new resources to come online between 2023 and 2028. D.21-06-035 states, "[i]n the event of any delay of a resource coming online when contracted to meet a capacity requirement in this decision, a [LSE] may include a contract provision for other capacity to serve as a bridge to the new resource."[9] D.23-02-040, D.24-09-006,[10] and D.24-02-047 expand upon the bridge resource requirements by, respectively: (1) allowing firm imports and resources from counterparties other than the developer of the primary resource to serve as bridge resources;[11] (2) allowing the use of bridge capacity to meet the Diablo Canyon replacement (DCR) requirements;[12] and (3) allowing the use of bridge capacity to meet the LLT requirements.[13]

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6 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.

7 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.

8 D.23-02-040.

9 D.21-06-035, at Ordering Paragraph (O¶) 10.

10 D.24-09-006, *Decision Allowing Bridge Resources for Alternative Compliance with Diablo Canyon Replacement Resource Category in Decision 21-06-035*, R.20-05-003 (Sept. 12, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K810/540810133.PDF.

11 *See* D.23-02-040, at 41.

12 *See* D.24-09-006.

13 *See* D.24-02-047.

SCE petitions the Commission to modify D.23-02-040 and D.24-02-047 to change the MTR bridge requirements in October through June for the generic capacity and LLT procurement requirements. SCE's requested modification provides that:

> [A]ny LSE who has executed long-term contracts to meet their generic capacity or LLT procurement requirements is not required to procure any bridge resources, and will not be penalized, for the non-Q3 months before their long-term resources come online, so long as the LSE met their month-ahead system RA requirement for that month by the final deadline for curing any RA deficiency.[14]

SCE requests this modification because, since the issuance of D.23-02-040, LSEs have encountered numerous delays to MTR projects resulting in the need to procure bridge resources for every month until the delayed projects ultimately come online, "regardless of an LSE's RA compliance position and the short-term reliability need for such bridge resources."[15] In addition, SCE demonstrates that MTR bridging is not needed for short-term reliability in the lower demand, non-Q3 months because: (1) LSEs have typically shown enough RA during non-Q3 months to meet their month-ahead obligations;[16] and (2) SCE's analysis demonstrates that even if no additional MTR capacity were to come online after June 1, 2024, excess capacity would still be available during the non-Q3 months of 2026.[17] SCE concludes that the requirements to procure bridge capacity for project delays has "resulted in unnecessary MTR bridge procurement for many months and increased costs for customers during a time when affordability is already a significant challenge for many."[18]

CalCCA agrees with SCE that customers will continue to face substantial costs for the over-procurement of unnecessary bridge resources unless D.23-02-040 and D.24-02-047 are

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14 PfM, at 4 (footnotes omitted).

15 *Id.,* at 3.

16 *See Id.,* at 10-11.

17 *See Id.,* at 11-12.

18 *Id.,* at 3.

modified.[19] CalCCA also agrees that if LSEs meet their month-ahead system RA requirements, bridging is unnecessary for short-term reliability given the supply buffer in the 2026 non-Q3 months.

CalCCA also requests that the Commission extend and clarify the bridging requirement modifications beyond SCE's requests for modification only to the generic and LLT requirements. First, the modified bridging requirements should extend to the DCR requirements, as the same logic applicable to the generic and LLT requirements applies. That is, there is no short-term reliability need to procure DCR bridge capacity in non-Q3 months and doing so would impose significant costs on customers. Second, the Commission should clarify the PfM to ensure that the modified bridging requirements apply to LSEs with both executed long-term contracts that are still active but delayed *and* executed long-term contracts that were terminated for circumstances outside the LSEs' control that LSEs are making good faith efforts to replace.

For these reasons, the Commission should:

- Adopt SCE's PfM to modify bridging requirements for generic and LLT procurement requirements;
- Extend the modified bridging requirements to DCR procurement requirements; and
- Clarify the PfM's applicability such that an LSE with an executed long-term contract that was terminated for circumstances outside the LSE's control and that the LSE is making good faith efforts to replace can also utilize the modified bridge requirements.

To implement the modifications within these recommendations, CalCCA provides redlines to SCE's proposed modifications to the findings of fact, conclusions of law, and ordering paragraphs in the Appendix, attached hereto.

[19] *See Id.,* at 3.

II. SCE'S PFM TO MODIFY BRIDGING REQUIREMENTS FOR GENERIC AND LLT PROCUREMENT REQUIREMENTS SHOULD BE ADOPTED AND EXTENDED TO DCR PROCUREMENT REQUIREMENTS

The Commission should adopt the PfM to modify bridging requirements for generic and LLT procurement requirements and extend the modified bridging requirements to DCR procurement requirements. Allowing LSEs that meet their month-ahead system RA requirements in the non-Q3 months to not procure any bridge resources in those months has the potential to provide significant affordability benefits without negatively impacting reliability. SCE's analysis demonstrates that even under conservative assumptions, including no new MTR procurement, there is sufficient excess RA in the non-Q3 months of 2026 such that continued bridge requirements in those months do not enhance system reliability. In addition, bridging requirements are often met by imports, which can be more expensive than traditional RA capacity given the bidding requirements adopted in D.20-06-028[20] and the demand for capacity in the Pacific Northwest during the winter months. If LSEs can meet their RA requirements in non-Q3 months, when there is sufficient excess RA supply, the Commission should not require them to procure bridge capacity for those months.

In addition, while SCE's PfM recommends modified bridging requirements only for the generic and LLT requirements, the Commission should extend the PfM's modified bridging requirements to DCR requirements. SCE's rationale for modifying the bridging requirements for generic and LLT requirements is also relevant for DCR resources. First, there is no short-term

[20] D.20-06-028, *Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020 (July 6, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF. This decision requires non-resource-specific imports to bid zero dollars or below or self-schedule during the availability assessment hours. Bridge capacity coming from non-resource-specific imports would be costly because they are expected to deliver energy during the availability assessment hours regardless of market price. Non-resource-specific imports will price into the bridge capacity contracts the risk that they do not recover costs in the CAISO energy market due to this bidding requirement.

reliability need to procure DCR bridge capacity in non-Q3 months. SCE's analysis shows excess capacity to meet RA requirements in off-peak months without counting the 2,280 MW of Diablo Canyon Power Plant RA capacity and with no new MTR procurement, *including DCR procurement*, coming online after June 1, 2024.[21]

Second, LSEs face significant costs to procure bridge resources for DCR requirements in all months, as they do for generic and LLT requirements. In fact, DCR bridge resources may be especially expensive given the additional requirements for DCR replacement bridge resources relative to generic MTR requirements.[22] Just like obtaining bridge capacity in non-Q3 months for generic and LLT requirements, obtaining bridge capacity in non-Q3 months for DCR requirements can be costly. While California typically does not experience capacity shortages in these months, LSEs seeking bridge capacity will still likely need to compete with other states in the Western Electricity Coordinating Council, like those in the Pacific Northwest with winter peaks.

Finally, if the Commission is concerned with the availability of a sufficient amount of zero emissions and renewable resources during the bridging period, LSEs will still have a RPS requirement to meet that will ensure progress is made toward clean energy goals. Further, the basis for the clean energy requirement for DCR is SB 1090,[23] which requires the Commission ensure Integrated Resource Plans avoid any increase in emissions of greenhouse gases as a result of the *retirement* of the Diablo Canyon Units 1 and 2 powerplant.[24] Utilizing clean bridge resources in only a subset of months as a temporary measure until an LSE can bring on new

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21 *See* PfM, at 11-14.

22 D.24-09-006. This decision requires DCR bridge resources to either emit zero greenhouse gases or otherwise eligible be under the Renewables Portfolio Standard (RPS) requirements.

23 *See* D.21-06-035, at 45.

24 Senate Bill No. 1090 (SB 1090) (Monning, Chapter 561, Statutes of 2018), Sec. 2.712.7(b): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1090.

permanent clean energy for the system does not appear to violate SB 1090 since it will not result in an increase in GHG emissions as a result of the retirement of Diablo Canyon Units 1 and 2. Ultimately, the new resources developed for DCR will have the attributes required by the Commission (*i.e.,* delivering clean energy from 5 p.m. to 10 p.m.). The need for clean resources that deliver in these hours, however, stems more from a future need to replace Diablo Canyon than any present need. There is no reason for the Commission to hold LSEs to stricter bridging requirements for DCR requirements than generic or LLT requirements.

Given these considerations, the Commission should adopt the PfM to modify bridging requirements for generic and LLT procurement requirements and extend the modified bridging requirements to DCR procurement requirements.

III. CLARIFICATION OF THE PFM IS REQUIRED TO ENSURE IT APPLIES TO LSES WITH EXECUTED LONG-TERM CONTRACTS THAT WERE TERMINATED FOR CIRCUMSTANCES OUTSIDE THE LSES' CONTROL THAT LSES ARE MAKING GOOD FAITH EFFORTS TO REPLACE

The Commission should adopt SCE's PfM with the clarification that the modified bridging requirements also apply to an LSE with an executed long-term contract that was terminated for circumstances outside the LSE's control and for which the LSE is making good faith efforts to replace. SCE requests modification of D.23-02-040 and D.24-02-047 to change the MTR bridge requirements for LSEs who have executed long-term contracts to meet their procurement requirements.[25] As written, the PfM could be interpreted as allowing the modified bridging requirements for only LSEs that have <u>*active*</u> executed long-term contracts for delayed projects. This could unnecessarily restrict the PfM by not allowing an LSE to use the modified bridging requirements that <u>*had*</u> an executed long-term contract, but the project since failed due to circumstances outside the LSE's control. In these circumstances, the LSE should be allowed to

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25 *See* PfM, at 4 (footnotes omitted).

use the modified bridging requirements while the LSE is procuring to replace the bridge capacity with permanent capacity under long term contract.

This clarification is consistent with D.21-06-035, which states, "[i]n the event of any delay of a resource coming online when contracted to meet a capacity requirement in this decision, a [LSE] may include a contract provision for other capacity to serve as a bridge to the new resource."[26] Given the supply chain difficulties developers are experiencing, even LSEs and developers making good faith efforts may be unable to deliver contracted projects on the schedule set upon contract execution. When delays are significant, terminating the contract and moving on to a new project could result in getting capacity online more quickly, and LSEs should not be penalized for doing so when it results in supporting identified reliability needs and meeting timelines established in the Commission's procurement orders.

Failure to adopt this clarification would dismiss the fact that a failed project or terminated contract that spurs bridge capacity procurement meets the intent of the MTR rules, and the good faith standard articulated by the Commission for assessing compliance. Prohibiting LSEs from using the modified bridge requirements for a contract that has been terminated, and that LSEs are taking good faith efforts to replace with permanent capacity, would also be counterproductive to reliability goals advanced in the MTR orders. It may also set perverse incentives for an LSE to remain in a contract when it is not in the best interest of reliability needs. For these reasons, the modified bridging requirements advanced in the PfM should apply to both LSEs with currently active executed contracts experiencing delays, and LSEs with executed long-term contracts that were terminated for circumstances outside the LSEs' control.

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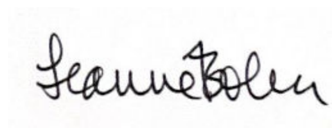
[26] D.21-06-035, O¶ 10.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests that the Commission: (1) adopt SCE's PFM; (2) apply the modified bridge requirements outlined in the PfM to the DCR requirements in addition to the generic and LLT requirements; and (3) clarify the PfM's applicability such that LSEs with executed long-term contracts that were terminated for circumstances outside the LSEs' control can utilize the modified bridge requirements.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 21, 2025

APPENDIX
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PETITION FOR MODIFICATION OF DECISIONS 23-02-040 AND 24-02-047

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

PfM's proposed text additions show as **bold and underlined**
CalCCA's proposed text additions show as **red bold and underlined**

D.23-02-040 FINDINGS OF FACT

12. Allowing imports from bridge resources (existing resources) contracted until a new resource has time to come online, if the imports used for bridge purposes meet current resource adequacy requirements at the time the contract is executed, will help enhance electric grid **reliability in the months of July through September. To avoid unnecessary costs to customers in months when bridge resources are not needed for short-term reliability, LSEs that have executed long-term contracts to meet their generic capacity requirements of D.21-06-035 or this order that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.**

D.23-02-040 CONCLUSIONS OF LAW

12. Import contracts from any resource and with any counterparty should be allowed to be used as bridge resources until such time as new resources can come online for the general procurement category identified in D.21-06-035 or the procurement required in this order, and not including Diablo Canyon replacement capacity or long lead-time procurement ordered in D.21-06-035, for a period of not more than three years. Imported energy used for this purpose should be allowed to count as long as it meets current resource adequacy requirements at the time the contract is executed. **LSEs that have executed long-term contracts to meet their requirements for the general procurement category identified in D.21-06-035 or the procurement required in this order that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.**

D.23-02-040 ORDERING PARAGRAPHS

8. For enhanced reliability purposes and compliance with the generic capacity requirements of Decision (D.) 21-06-035 or this order, but not for the Diablo Canyon replacement capacity or long lead-time resource procurement required in D.21-06-035, a load serving entity **(LSE)** may contract

for imported energy as a bridge until the online date of a new compliance resource, from any resource and with any counterparty, for a period of not more than three years. The bridge contract for imported energy must meet resource adequacy requirements at the time the contract is executed. **LSEs that have executed long-term contracts to meet the generic capacity requirements of D.21-06-035 or this order that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.**

D.24-02-047 CONCLUSIONS OF LAW

22. The Commission should require LSEs that do not meet their LLT resource procurement requirements by June 1, 2028 to procure generic replacement capacity, either through long-term contracts or bridge contracts defined in D.21-06-035 and D.23-02-040, **for the months of July through September** until such time as their LLT resources can come online, by no later than June 1, 2031. **LSEs that have executed long-term contracts to meet their LLT resource procurement requirements that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.**

D.24-02-047 ORDERING PARAGRAPHS

19. Any load-serving entity **(LSE)** that does not meet its required long lead-time (LLT) procurement requirements in Decisions (D.) 21-06-035 and D.23-02-040 by June 1, 2028 shall procure an equal amount (in net qualifying capacity) of the balance of its unmet LLT requirements through a bridge contract, which includes firm imports as defined in D.23-02-040, or long-term contracts that otherwise meet the characteristics required for generic procurement in D.21-06-035, to cover the shortfall in the months of July through September until its LLT resources come online, from June 1, 2028 through June 1, 2031, at a minimum. **LSEs that have executed long-term contracts to meet their LLT procurement requirements in D.21-06-035 and D.23-02-040 that are delayed or terminated are not required to procure any bridge** resources to meet those requirements, and will not be penalized, for the months of October **through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.**

D.24-09-006 CONCLUSIONS OF LAW

2. Allowing short-term bridge contracts for a period of no more than three years for compliance with the Diablo Canyon Power Plant replacement resource requirements in D.21-06-035 represents the potential for short-term reliability benefits**, for the months of July through September**. **LSEs that have executed long-term contracts to meet their Diablo Canyon Replacement procurement requirements that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the**

months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.

D.24-09-006 ORDERING PARAGRAPH

New: Any Load-serving entity (LSE) using the alternative compliance options in Ordering Paragraph 1 that has executed long-term contracts to meet its Diablo Canyon Replacement procurement requirements that are delayed or terminated are not required to procure any bridge resources to meet those requirements, and will not be penalized, for the months of October through June before their long-term resources come online so long as the LSE met their month-ahead system resource adequacy requirement for that month by the final deadline for curing any resource adequacy deficiency.

April 22, 2025

Via Electronic Email

California Public Utilities Commission – Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
(EDTariffUnit@cpuc.ca.gov)

Re: Protest of Joint CCAs to Pacific Gas and Electric Company Advice Letter 7558-E

Dear Energy Division Tariff Unit:

Pursuant to the California Public Utilities Commission's ("Commission") General Order ("GO") 96-B, Central Coast Community Energy ("3CE"), Marin Clean Energy ("MCE"), Pioneer Community Energy ("Pioneer"), Ava Community Energy ("Ava"), and Silicon Valley Clean Energy ("SVCE") ("Joint CCAs") hereby protest Pacific Gas and Electric Company's ("PG&E") Advice Letter ("AL") 7558-E. [1] AL 7558-E was submitted by PG&E on April 2, 2025.

PURPOSE

The Joint CCAs protest AL 7558-E on the grounds that, as identified in General Rule 7.4.2(6) of GO 96-B, the "relief requested in the advice letter is unjust, unreasonable, or discriminatory." More specifically, because PG&E's unilateral decision to pause enrollment in the Expanded Ag Pilot is unreasonable, discriminates against unbundled customers, and exceeds the scope of Commission authorization in D.24-01-032, the joint CCAs request that the Commission reject AL 7558-E and instead direct PG&E to file a request to pause enrollment as a Tier 2 advice letter. Any such request must include:

- Detailed support for the claim that continued enrollment exceeds PG&E's "operational processes and capabilities";
- A detailed process and timeline for re-opening enrollment;
- Analysis of relative enrollment and incentive distribution between bundled and unbundled customers;

[1] References below to "General Rules" are to the general rules identified in GO 96-B.

- Clarifications on whether pilot changes and additional customer tools will be provided to unbundled customers; and
- An explanation of how PG&E will collaborate with CCAs to address these issues prior to recommencing enrollment.

BACKGROUND

On January 6, 2024, the Commission adopted Decision ("D.") 24-01-032 which, in part, directs PG&E to expand the VCE AG Pilot to bundled and unbundled customers on AG-A1, AG-A2, AG-B, and AG-C rates across PG&E's service territory.[2] Additionally, the Decision authorizes $8,000,000 in customer automation incentives, for which both unbundled and bundled customers are eligible, along with up to $1,800,000 in CCA incentives of $20 per unbundled kW-year.[3]

Per D.24-01-032, any CCA in PG&E's service territory was eligible to file a Tier 1 AL by March 1, 2025, to notify the Commission that it will commence enrollment in the PG&E Ag Pilot or the PG&E Expanded Pilot 2 by June 1, 2025.[4] While PG&E originally planned to launch the PG&E Ag Pilot in June of 2024, PG&E requested an extension of time to commence enrollments in the expanded pilots to November 1, 2024.

In D.24-01-032, the Commission set an enrollment target of 50 megawatts (MW) for the Expanded Ag Pilot[5] and found it reasonable to authorize the Expanded Ag Pilot without a cap on enrollment.[6] Instead, the Commission adopted scaling budget provisions for PG&E's program administration costs, including an upfront budget and an additional $1,250,000 upon three subsequent enrollment milestones: 12.5 MW, 25 MW, and 37.5 MW.[7] The Decision specifies that PG&E shall file a Tier 1 AL to notify the Commission when pilot enrollment reaches 12.5 MW, 25 MW, or 37.5 MW,[8] but does not direct PG&E to pause enrollment in pilots once these milestones are reached. While the Commission made it clear that it did not expect PG&E or participating CCAs to enroll an unlimited number of customers into the Expanded Ag Pilot,[9] nowhere in the Decision does the Commission authorize PG&E to unilaterally pause enrollments or provide guidance on the process and timeline by which PG&E may pause or stop enrollment.

On April 2, 2025, PG&E submitted AL 7558-E pursuant to D.24-01-032, notifying the Commission that PG&E's Expanded Ag Pilot achieved an enrollment level of 12.5 MW on February 17, 2025, an enrollment level of 25.0 MW on March 6, 2025, and an enrollment level of 37.5 MW on March 21, 2025.[10] PG&E's AL indicates that PG&E surpassed 50 MW of

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[2] D. 24-01-032, Conclusion of Law 3.
[3] D. 24-01-032, Attachment A ("CCA incentives are paid to a CCA once per 12-month period, prorated, based on the aggregate kilowatts enrolled in the applicable expanded pilot in their service area.").
[4] D. 24-01-032, Conclusion of Law 30.
[5] D. 24-01-032, Ordering Paragraph 1.
[6] D. 24-01-032, Conclusion of Law 1.
[7] D. 24-01-032, Conclusion of Law 12.
[8] *Id.*
[9] D. 24-01-032, p. 16.
[10] AL 7558-E at 2.

enrollment on March 28, 2025.[11] PG&E's AL further states that PG&E will be temporarily pausing enrollments starting April 4, 2025. D.24-01-032 authorized CCAs to notify the Commission by March 1, 2025, of an intent to commence enrollment in the pilot by June 1, 2025. PG&E's AL attempts to pause enrollment a mere 23 business days after the deadline for CCAs to file an AL indicating intent to participate, and nearly two calendar months before the CCAs' deadline for commencing enrollments in the pilot.

CCAs who joined the pilot and noticed PG&E and the Commission prior to March 1, 2025, in some cases months before, faced additional barriers to beginning enrollment.[12] In September 2024, PG&E notified the CCAs that PG&E would require CCAs to sign a service agreement (Attachment A) in order to be able to begin enrolling customers. Even though PG&E had stated, and the Commission found, that such a contract would be unnecessary,[13] the CCAs worked with PG&E to develop PG&E's proposed agreement so that it would be acceptable to both parties in a good faith effort for successful partnership. Finalization of the service agreement did not occur until mid-January, 2025. Furthermore, during this period of contract negotiation, PG&E informed the CCAs that in order for a CCA to use its own time-of-use rates for the calculation of enrolled Agricultural customer savings, the CCA would be required to contract directly with the vendor Polaris, representing an additional enrollment step that could have been shared earlier. CCAs were therefore unable to begin enrolling unbundled customers in the pilot until months after it became available to bundled customers.

PROTEST

The Joint CCAs protest AL 7558-E on the grounds that, as identified in General Rule 7.4.2(6), the "relief requested in the advice letter is unjust, unreasonable, or discriminatory." The Joint CCAs support PG&E's plan to implement new enrollment support features such as an incentive reservation system and other processes to manage customer expectations as they relate to remaining available incentives. However, it is unreasonable and discriminatory against unbundled customers to pause enrollment without:

- an explicit duration to the pause requested;
- a clear timeline for PG&E's process to re-open program enrollment;
- more details on how and why PG&E has exceeded the operational processes and capabilities necessary to support additional participants;
- clarifications on whether pilot changes and additional customer tools will be provided to unbundled customers, and;

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[11] *Id.*

12 *See AL 3CE 40-E,* submitted on May 3, 2024. 3CE was the first CCA to notify the Commission of its intent to join the Expanded Ag Pilot.

[13] *See PG&E Reply Comments to Proposed Decision,* R.22-07-005, Jan. 12, 2024, at 2: "Cal Advocates proposes contracting requirements between CCAs and PG&E for cost transparency and clear responsibilities. However, if CCAs (except VCE) are being paid by a per kW-yr enrolled incentive, contracts as proposed by Cal Advocates are not necessary." *See also D.24-01-03* at 73*:* "PG&E argued that no additional contracting requirements or delineation of responsibilities is needed for other CCAs that participate in the pilot because those CCAs will receive a per kW-yr enrollment incentive rather than administrative costs. We agree that no additional contracting requirements are needed for CCAs to receive enrollment incentives."

- how PG&E will collaborate with CCAs to address these issues prior to recommencing enrollment.

For the following reasons, the Joint CCAs protest AL 7558-E:

1. PG&E does not have the unilateral authority to pause enrollments for both bundled and unbundled customers.

PG&E has exceeded the scope of the Commission's authorization provided by D.24-01-032 by unilaterally pausing program enrollment for both bundled and unbundled customers through a Tier 1 advice letter. While the Joint CCAs understand the reasoning behind PG&E's pause in enrollment, halting pilot enrollment for bundled and unbundled customers is unreasonable without an explicit duration to the pause requested, a clear timeline for PG&E's process to re-open program enrollment, more details regarding how and why PG&E has "surpassed the operational processes and capabilities necessary to support" customers,[14] and how PG&E will address these issues and collaborate with CCAs prior to recommencing enrollment. As the pilot administrator, PG&E needs to clearly communicate with the CCAs who are reliant upon PG&E for their own customer enrollment, especially when implementing changes that will directly impact CCAs' ability to offer the pilot. Further, because D.24-01-032 does not explicitly provide authorization or a process for PG&E to unilaterally pause pilot enrollments, seeking to implement an enrollment pause via a Tier 1 advice letter is not an appropriate procedural avenue. Thus, the Joint CCAs request that the Commission reject AL 7558-E and instead direct PG&E to file a request to pause enrollment via a Tier 2 advice letter.

2. PG&E fails to provide the information necessary for the Commission to approve a pause in enrollment.

In AL 7558-E, PG&E states:

> "We will be temporarily pausing enrollments on the Expanded Ag Pilot starting April 4, 2025. This will allow time to evaluate, plan and implement pilot changes to support customer enrollments beyond 50 MW and determine a level of supportable enrollment with existing budget. In addition, we will plan and implement pilot changes to manage customer expectations related to incentives. These could include customer dashboards, an incentive reservation system, or possibly other new processes. Upon the completion of these pilot changes, PG&E would notify stakeholders at least 30 days before re-opening the Expanded Agricultural Pilot for new enrollments."[15]

While the Joint CCAs appreciate PG&E's commitment to supporting further enrollments and considering improvements to the experience of both bundled and unbundled customers within the expanded pilot, the Joint CCAs are concerned with the lack of detail in PG&E's AL. Implementing a customer dashboard, while potentially beneficial, is likely to take a significant amount of time for PG&E to develop and implement. Without additional information on when PG&E expects to re-open

[14] AL 7558-E at 2.
[15] AL 7558-E at 2.

enrollment, as well as how PG&E will work with CCAs in planning and implementing changes to the pilot, the CCAs are left without clarity as to potential impacts to unbundled customers, who are paying for administration of the pilot through distribution rates, and how to proceed with customer outreach and pilot program planning.

The Joint CCAs are concerned that without modification, Commission approval of AL 7558-E would constitute approval of an indefinite pause in enrollment with no clear path forward, as granting the relief requested within PG&E's AL without additional information would unreasonably permit PG&E to pause enrollment for both bundled and unbundled customers with no indication of when, or if, PG&E would re-open enrollment. The Joint CCAs have endeavored to be reasonable partners with PG&E and elected to join the expanded pilot program because of the potential benefits these programs can provide to both customers and the grid. These benefits could be limited by an indefinite pause; thus, it is critical that PG&E provide more robust details on its plan for further pilot enrollment and refinement.

3. PG&E's pilot program administration has discriminated against unbundled customers by overstepping Commission direction.

Ultimately, PG&E's AL shines a light on the ongoing uncertainty related to the implementation of the expanded pilot programs authorized by D.24-01-032 and highlights the need for clear Commission direction at this stage of pilot administration. While the CCAs understand that unexpected hurdles have surfaced in the implementation of the expanded pilots, lack of clarity on PG&E's role and responsibilities in administering pilot programs causes confusion and creates barriers that have hindered, and continue to hinder, successful partnership between PG&E and the participating CCAs. Leaving discretion to PG&E has delayed CCA enrollment thus far, and allowing for further delays through authorizing a pause without a clear plan for recommencing enrollment would only exacerbate this ongoing issue.

For example, contrary to specific Commission direction, PG&E insisted that CCAs complete a contractual agreement prior to unbundled customers being able to start the pilot, which inhibited CCA participation in the expanded pilots. Despite the findings of the Commission in D.24-01-032 that "no additional contracting requirements are needed for CCAs to receive enrollment incentives"[16] and the claim from PG&E that "no additional contracting requirements or delineation of responsibilities is needed [CCAs other than VCE] that participate in the pilot because those CCAs will receive a per kW-yr enrollment incentive rather than administrative costs,"[17] PG&E required CCAs to sign an agreement that defines joint, CCA, and PG&E obligations for pilot participation in order to enroll unbundled customers. During agreement negotiations, SVCE requested that language be added specifying how PG&E would prioritize customer enrollment selections (e.g., in the order the enrollment applications were filed). PG&E did not agree that this language was needed at the time, resulting in opacity around how PG&E selects which customer are enrolled in the pilot and the proportion of bundled to unbundled customer enrollment and whether that proportion matches the number of applications received.

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[16] D.24-01-032 at 3.
[17] *Id.*

In an effort to be good partners, the CCAs worked with PG&E from September of 2024 through January of 2025 to develop and execute Attachment A, *Agreement for Community Choice Aggregators Participating in the Hourly Flex Pricing Pilots* ("Agreement"). PG&E provided a final version of the Agreement to the CCAs on January 17, 2025. The Agreement describes the Hourly Flex Pilot ("HFP") participation options available for CCAs and indicates that CCAs that elect to participate with PG&E's real time pricing ("RTP") generation rates are "eligible to join the HFP Pilots immediately after the Effective Date," with the "Effective Date" defined within the Agreement as "the date of the last signature of all the Parties to this agreement." After final review and the signatory process, 3CE's, Ava's, SVCE's, and Pioneer's Agreements with PG&E were not finalized until January 31, 2025, nearly three full months after program enrollment was scheduled to begin, and MCE's was not finalized until after PG&E filed AL 7558-E. The development and execution of this Agreement significantly delayed unbundled customer enrollment in the program.

However, during the time that the Agreement was being executed with participating CCAs, PG&E was moving forward with its own bundled customer enrollment. AL 7558-E is silent on the percentage of bundled versus unbundled customers enrolled in the Expanded Ag Pilot. Based on informal conversations with PG&E, the Joint CCAs understand that enrollment to date has disproportionately favored bundled customers. The lack of formal disclosure regarding enrollment proportions is concerning. The discriminatory delay for unbundled customers seeking to participate in the program is particularly discouraging given that now, after only two months of executing the Agreement, PG&E is requesting to pause further enrollment without any information on when CCAs may expect to be able to continue enrollment.

4. PG&E's discriminatory administration could cause appreciable harm to unbundled customers.

The Joint CCAs are also concerned that PG&E's program administration will prevent unbundled customers from accessing the potential benefits afforded to bundled customers. The Expanded Ag Pilot has a set amount for technology incentives for customers. As PG&E's AL indicates, "…there is concern from customers and ASPs on how quickly automation technology incentives will be exhausted if enrollments exceed 50 MW, and if customers who invest in automation technology with the expectation of receiving an incentive will actually be able to do so."[18] The Joint CCAs would add an additional concern to this point: because CCAs were delayed in enrolling unbundled customers, and PG&E met its current enrollment levels primarily with bundled customers, bundled customers will receive the majority of the technology incentive funds.[19]

If the Commission approves a pause in enrollment for PG&E to plan and implement pilot changes to manage customer expectations related to incentives, PG&E should evaluate and disclose the proportion of incentives that have been allocated to bundled versus unbundled customers. While the Decision does not set aside any of the technological incentives for

[18] AL 7558-E at 2.
[19] This could be especially exacerbated by the fact that total enrolled load is being counted towards the enrollment targets, instead of the total shiftable or addressable load.

unbundled customers, these incentives are funded by all ratepayers, and PG&E should endeavor to maintain parity in their allocation to bundled and unbundled customers upon recommencing enrollment since unbundled customers have faced additional delays in pilot participation. PG&E should also provide data on the CCA incentive funds available. If PG&E were to prematurely stop enrollment prior to these funds being depleted due to meeting enrollment levels with primarily bundled customers, these funds would be stranded.

Finally, PG&E should include details on how this pause and its plan for implementing pilot changes will benefit unbundled and bundled customers alike. CCAs should be included in PG&E's development of tools and changes to improve customer experience to ensure that unbundled customer needs are considered. The CCAs understand PG&E's need to pause the pilot to ensure successful implementation, but as program administrator, the CCAs are reliant upon PG&E for their own customer enrollment.

The Joint CCAs believe that PG&E's AL indicates that Commission direction is needed not only on the process that PG&E should follow to pause enrollment, as the administrator of the pilot, but also on other potential areas of confusion that could surface in the near future. These areas of uncertainty include the process if the HFP Pilot 2 exceeds expected enrollment, how to ensure parity between the allocation of incentives, and any other details necessary to ensure that PG&E is able to sustain program administration through 2027 as authorized in the Decision. It is important to minimize delays and hurdles to maximize the benefits that the Commission envisioned in extending these pilots. Granting a pause to the Expanded Ag Pilot without equitable consideration to CCAs or any details on the duration and plan for resuming enrollment would create another unreasonable barrier to successful enrollment of unbundled customers in the pilot.

Absent a Commission-approved process for PG&E, as administrator of the pilot, to pause enrollment for bundled and unbundled customers, it would be unreasonable to grant PG&E's request without additional details on when PG&E will re-start enrollment as well as how and why PG&E "surpassed the operational processes and capabilities necessary to support" customers and what will be done to address these issues. Without these details, CCAs cannot provide clear communication to interested customers on when they can expect to be able to enroll in the program, or whether they will receive the technology incentive. To that end, PG&E should also provide updates on its anticipated timeline for reaching the target for Expanded Pilot 2, the proportion of bundled and unbundled customers enrolled, as well as its approach to resolving similar operational and incentive issues currently facing the Expanded Ag Pilot

SUSPENSION AND NOTICES

Under General Rule 7.3.4(1), an advice letter will become effective 30 days after the date of filing if an advice letter has not been protested and the Energy Division has not suspended the advice letter by the end of the initial review period. The initial review period is the 30 days immediately following the filing.[20] AL 7558-E was filed on April 2, 2025, and thus AL 7558-E would otherwise be deemed approved on or about May 2, 2025. In light of this protest, the Joint

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[20] *See* General Rule 7.5.2 ("Initial Review Period; Suspension; Status Report").

CCAs request that the Energy Division suspend AL 7558-E. The Joint CCAs sent this protest to PG&E on April 22, 2025, the same day on which the protest was submitted to the Energy Division.[21]

CONCLUSION

Because PG&E's unilateral decision to pause enrollment in the Expanded Ag Pilot is unreasonable, discriminates against unbundled customers, and exceeds the scope of Commission authorization in D.24-01-032, the Commission should reject AL 7558-E and direct PG&E to file a request to pause enrollment as a Tier 2 Advice Letter. Further, the Commission should clarify that any such request must include:

- Detailed support for the claim that continued enrollment exceeds PG&E's "operational processes and capabilities";
- A detailed process and timeline for re-opening enrollment;
- Analysis of relative enrollment and incentive distribution between bundled and unbundled customers;
- Clarifications on whether pilot changes and additional customer tools will be provided to unbundled customers; and
- An explanation of how PG&E will collaborate with CCAs to address these issues prior to recommencing enrollment.

Finally, the Commission should direct PG&E to re-open enrollment, at least unbundled customers, until a pause is specifically authorized through the Tier 2 Advice Letter process. The Joint CCAs thank the Commission for its consideration of this protest.

Respectfully,

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[21] On April 22, 2025, at 12:32 PM, PG&E filed AL 7558-E-A, a supplement to AL 7558-E to remove language of the program "pause" and replace AL 7558-E in its entirety. Due to limited time and PG&E's request in AL 7558-E-A for the Commission to maintain the protest and comment deadline of April 22, the Joint CCAs still submit this protest to ensure all issues are addressed by the Commission.

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ATTACHMENT A:
AGREEMENT FOR CCAS PARTICIPATING IN THE HOURLY FLEX PRICING PILOTS

This Agreement (Agreement) for Community Choice Aggregators (CCA) participating in the Hourly Flex Pricing Pilots (HFP Pilots) is entered into by and between Pacific Gas and Electric Company (PG&E), a California corporation, and the named CCA below and shall become effective as of the date of the last dated signature of all the Parties to this Agreement (Effective Date). PG&E and CCA may sometimes be referred to herein individually as a "Party" and collectively as the "Parties".

WHEREAS, the California Public Utilities Commission (CPUC) has authorized PG&E to conduct the HFP Pilots, with day-ahead hourly real-time pricing (RTP) rate elements for generation, distribution, subscription and transactive elements pursuant to the following regulatory approvals: CPUC Decision 24-01-032, PG&E's Advice Letter 7222-E[1], Advice Letter 7222-E-A[2], Advice Letter 7222-E-B[3], Advice Letter 7223-E-A[4] and Advice Letter 7223-E-B[5] for the Expanded Pilots, and PG&E's Advice Letter 7234-E-A[6], and CPUC's Resolutions E-5192, E-5326 and E-5358 for the Vehicle Grid Integration (VGI) Pilots (Regulatory Approvals), (together the "Hourly Flex Pricing Pilots", or "HFP Pilots").[7]

WHEREAS, the CPUC has authorized the participation of CCAs that provide the generation RTP rate element for their customers in the HFP Pilots.

WHEREAS, the CCA wishes to enable its customers to participate in the HFP Pilots by providing its customers the RTP generation rate component, shadow billing, and giving their customer an HFP generation credit if the RTP bill, including transactive elements, if any, is lower than the otherwise applicable tariff (OAT), as further described below.

This Agreement has no impact on the existing CCA/PG&E billing processes as it relates to Electric Rule 23 – Community Choice Aggregation Services.

Glossary of Terms

Shadow Bill – An approach to provide HFP Pilot participants with compensation for any load shift and/or exports by the participant in response to the HFP rate. Participants will continue to pay their current electric bill under the OAT and will also receive a shadow bill, which they will not pay. The shadow bill would illustrate a customer's potential savings and/or revenue for exports under the HFP rate.

Shadow Bill True-up – A Shadow Bill reflective of the cumulative HFP charges and credits which typically occurs after a customer is enrolled for 12 months on the HFP Pilot. The customer will receive any accumulated credits (i.e., generation and distribution), at the time of true-up, typically within 12 months. Shadow Bill True-up for solar customers will coincide with their solar true-up period, which may occur before their 12 months enrollment date on the HFP Pilot.

Otherwise Applicable Tariff (OAT) on the Shadow Bill – The existing tariff a customer is currently enrolled in. For the purpose of the shadow billing under the out of the box (OOTB) or Hybrid Options, PG&E's OAT prices will be used as a proxy, which may be different from the CCA OAT prices.

RTP Generation Component – A day-ahead hourly generation rate equal to the combined marginal energy costs (MEC) and marginal generation capacity costs (MGCC).

[1] Approved September 3, 2024.

[2] Approved September 3, 2024.

[3] Approved September 3, 2024.

[4] Approved September 3, 2024.

[5] Approved August 28,2024.

[6] Approved May 3, 2024.

[7] Approved May 5, 2023, and July 11, 2024, respectively.

HFP Generation Credit – A dollar amount associated with the generation component of the RTP rate, calculated as the difference between the OAT bill and the Shadow bill over a true up period (typically 12 months from enrollment date, and every anniversary thereafter). The CCA is responsible for paying the HFP Generation Credit to their customers under the HFP Pilots.

RTP Distribution Component – A day-ahead hourly distribution rate designed to recover the Primary Distribution Costs, which is dependent on the location of the customer. The RTP Distribution Component utilizes the scarcity pricing concept, with prices dependent on the forecasted load on a representative circuit with similar load characteristics to the customer's circuit.

HFP Distribution Credit – A dollar amount associated with the distribution component of the RTP rate, calculated as the difference between the OAT bill and the Shadow bill over a true up period (typically 12 months from enrollment date, and every anniversary thereafter). PG&E is responsible for paying the HFP Distribution Credit to all customers under the HFP Pilots.

Unbundled Customers – customers who receive delivery services from PG&E but obtain energy from another supplier. In this agreement, unbundled customers receive energy from a CCA.

Effective Date – The date of the last dated signature of all the Parties to this Agreement

Service Agreement Identification (SAID) Number - A 10-digit number that identifies a customer's specific arrangement with PG&E. It documents details such as the customer's rate plan, billing days, and metering information.

THEREFORE, in consideration of the mutual undertakings set forth below, the Parties agree as follows:

I. JOINT OBLIGATIONS

A. Customer Enrollment Requirements. Customers interested in participating in any of the HFP Pilots must submit an HFP Pilot enrollment application on PG&E's website including agreement to be bound by the applicable HFP Pilot participation terms and conditions. PG&E will assess the eligibility of interested customers based on the respective pilot requirements, pursuant to the Regulatory approvals. Specifically, PG&E will conduct a dual participation check for PG&E programs and all supply-side DR programs for Expanded Pilots according to the rules outlined in the AL 7223-E-B[8], and successor advice letters on dual participation; and for the VGI pilots, PG&E will conduct dual participation checks for PG&E programs, all supply-side DR programs, and also confirm an enrollment in the mandated ELRP Subgroup A5 Phase 2 of the VGI Pilots. PG&E will create a list by SAID Number (Applicant List) to be provided to the CCA for approval on a weekly basis. PG&E will include all customers that have submitted an HFP Pilot enrollment application on the Applicant List and will specify if customers are eligible/ not eligible to participate based on the respective pilot requirements. If customers are not eligible, PG&E will specify the reason for non-approval (Ineligibility Reason). CCAs agrees to conduct a dual enrollment check for any event-based CCA load-modifying DR program. The CCA agrees to return to PG&E each Applicant List with an indication of which CCA customers are approved/ not approved with a reason for such non-approval (Rejection Reason) (e.g., CCA customer is participating in a supply-side DER resources or other event-based load-modifying programs or pilots operated by the CCA, or CCA has reached their internal enrollment target). For all CCA customers, PG&E will complete their HFP Pilot enrollment if eligible and approved by the CCA and communicate the enrollment status to the customer. Similarly, PG&E will communicate the enrollment status to the customer if the customer

[8] Dual Participation in PG&E's Agricultural Pilot and Expanded Pilot 2 AL 7223-E-B has been approved effective August 20th, 2024. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7223-E-B.pdf

is ineligible (for HFP Ineligibility Reason or CCA Rejection Reason). PG&E's confirmation of the CCA customer HFP enrollment will be available in the HFP Report (see more details in Section III.C).

B. Shadow Bill True-up and HFP Credit Alignment. The Parties will make reasonable efforts to align the Shadow Bill True-up with the timing of the CCA HFP Generation Credit and PG&Es HFP Distribution Credit so they can be presented on the same monthly customer bill, should the CCA decide to apply a bill credit.

C. Customer Support. All general customer inquiries about HFP Pilot participation, as well as the delivery portion of the RTP pricing will be handled by PG&E. PG&E may hand off CCA-specific customer inquiries to CCA as appropriate. For the OOTB and Hybrid solution, CCA may choose not to rely on PG&E and may take on the responsibility for the customer support. Any questions related to the Custom option CCA generation prices, PG&E will direct to CCA to address.

II. CCA'S OBLIGATIONS

R.S. A. HFP Pilots Participation Choice. (Select all that the CCA wants to join by the prescribed deadline[9] as applicable) The CCA may participate in one or more of the following HFP Pilots:

☒ Expanded Pilot #1 or AgFIT Pilot targeting Agriculture Customers

☒ Expanded Pilot #2 targeting Residential, Commercial, Industrial, as well as Small and Medium Business Customers

☐ Phase 2 of the VGI Pilots[10]

Each customer SAID may only enroll and participate in one of the HFP Pilots at a time.

R.S. B. HFP Pilots Participation Options. (Select only one) The CCA has a choice of participating in the HFP Pilots in one of the following ways for its RTP generation component (only a single option if participating in multiple HFP Pilots):

☒ Out of the Box (OOTB)

☐ Hybrid

☐ Custom

OOTB Option – CCA agrees to use PG&E's RTP generation prices and PG&E's OAT for the shadow billing purposes of the CCA's unbundled customers. The CCA is eligible to join the HFP Pilots immediately after the Effective Date. PG&E and the CCA will make reasonable efforts to onboard the CCA within 30 calendar days.

Hybrid Option – CCA agrees to use PG&E's RTP generation price structure with Marginal Generation Capacity Cost adjustment(s) provided by the CCA (as a flat amount[11]), PG&E's Marginal Energy Cost, and PG&E's OAT for the shadow billing purposes of the CCA's unbundled customers. The CCA is eligible to join the HFP Pilots immediately after the Effective Date. PG&E and the CCA will make reasonable efforts to onboard the CCA within 30 calendar days.

Custom Option – CCA agrees to provide its own RTP generation prices and/or CCA OAT to PG&E for shadow billing calculation. The timing is subject to the full development cycle, including

[9] Decision 24-01-23 (p.52): "Any CCA in PG&E's service territory may file a Tier 1 advice letter by March 1, 2025 to notify the Commission that it will commence enrollment in a PG&E expanded pilot by June 1, 2025."

[10] V2M Microgrids Pilot is out of scope

[11] The option to implement as a percentage will be explored in the future

gathering business requirements, development and implementation on both CCA's billing agent and PG&E's third-party implementer timeline.

CCA may start with any of the options indicated above and switch at any point, subject to implementation timelines, in which case the CCA is required to amend this Agreement.

C. Customer Credit for the HFP Generation Component:

a. The CCA is responsible for the RTP generation component for its customers and the shadow bill HFP Generation credit for the CCA's customer if the customer's RTP bill generation component is lower than the customer's OAT shadow bill for generation under the method selected in Section II B., on a 12-month cumulative basis or when applicable.

b. The CCA is also responsible for transactions on the transactive platform for the RTP generation component for the HFP Pilots (if applicable[12]).

c. If CCA's customer shadow bill for RTP generation component is lower than the customer's OAT under the method selected in Section II B, for the 12-month period or when applicable, the CCA agrees it will provide its customer a HFP Generation Credit as either a bill credit or check.

d. CCA will review the RTP generation component calculation and HFP Generation credit of their customers. CCA will have up to one year from shadow bill issuance to dispute any discrepancies. PG&E will continue to issue shadow bills as per determined cadence unless CCA notifies PG&E. CCA will have access to all necessary information to conduct this review, which is presented in Section III.D "Data Access and Reporting".

e. If the shadow bill for RTP generation component for the customer is higher than the OAT shadow bill for generation under the method selected in Section II B, for the 12-month period or early true-up, the CCA agrees the customer will not be financially responsible for the RTP shadow bill, for purposes of the HFP Pilots.

f. Nothing in this Agreement is intended to interfere with the CCA's right to bill its customer using the CCA's own OAT.

D. Calculation to avoid double compensation. The HFP Pilots are subject to Commission requirements to avoid double compensation for customers that are concurrently enrolled in demand response programs for which dual participation is permitted. For CCA programs, the CCA will be responsible to apply the methodology and perform the calculations as required to avoid double compensation.

III. PG&E'S OBLIGATIONS

A. CCA Enrollment Bonus.

a. CCA Compensation. Per PG&E AL-7222 for Expanded Pilots, and Resolution E-5358[13], a participating CCA will receive an enrollment incentive (CCA Bonus) of \$20/kW-year for a CCA customer in the CCA's service territory that participates in the pilot for which the CCA provides an hourly RTP generation rate, up to \$1.8M for each Expanded Pilots #1 and #2, and up to \$500k for Phase 2 of the VGI Pilots. The enrolled load for the CCA

[12] Transactive element is only applicable for Expanded Pilot #1

[13] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K477/551477718.PDF

Bonus will be determined as described in AL-7222 (Enrolled Load). PG&E will provide Enrolled Load per SAID in the Applicant List, if available. For customers with insufficient load history data, the Enrolled Load information will be provided in the CCA Enrollment Bonus Report, as noted in Section III b.

b. CCA Enrollment Bonus Disbursement. PG&E will allocate a CCA Bonus with the amount to be prorated based on the duration from the date of the customer's enrollment to the year's conclusion. PG&E will distribute CCA Bonus annually in Q1 for the prior calendar year. For the purpose of this allocation, PG&E will employ its established CCA payment remittance process. Furthermore, PG&E is committed to monitoring the amounts of CCA Bonuses disbursed and will report these figures annually, as outlined in Section III D.

B. Customer Credit for the HFP Distribution Component:

a. PG&E is responsible for the RTP distribution rate component associated with its delivery service to the CCA customers. Additionally, PG&E is responsible for providing the HFP distribution credit on shadow bills to CCA customers if the RTP distribution component of the bill is lower than the distribution component of the customer's OAT, on a 12-month cumulative basis, or when applicable.

b. If CCA's customer shadow bill for RTP distribution component is lower than the customer's OAT shadow bill for distribution under the method selected in Section II B for the 12-month period or when applicable, PG&E agrees to provide CCA customers a HFP Distribution Credit on the bill.

c. If the shadow bill for RTP distribution component for the CCA customer is higher than the OAT bill under the method selected in Section II B for the 12-month period or when applicable, PG&E agrees the CCA customer will not be financially responsible for the RTP shadow bill, for the purpose of the HFP Pilots.

C. Data Access & Reporting:

a. Customer Shadow Bills. PG&E will provide the CCA with access to its customers' shadow bills via the Enterprise Secure File Transfer (ESFT) within 10 business days of delivery to the customer, which will contain data on customer HFP Pilot performance as well as the customer's OAT shadow bill.

b. HFP Report. PG&E will provide a report to CCA on a monthly basis that tracks their customer participation and HFP Pilots performance details, including, but not limited to customer name, SAID, enrollment date, HFP generation and distribution components, subscription, OAT, true-up date, HFP generation and distribution credits.

c. Hourly Interval Data. PG&E will provide hourly interval data via existing EDI process for CCA enrolled customers that CCA marks in the Applicant List under section I A.[14]

d. Shadow Bill Workbook. PG&E will provide a shadow bill workbook with an example for CCA to use for their own review.

e. Transactive Data. PG&E will provide transactive data per SAID (applicable for the Expanded Pilot #1 only).

[14] Currently, non-NEM export data required for bidirectional customers enrolled in the VGI Pilots is not available via standard EDI feed as HFP Pilots are not built in PG&E's billing system. PG&E is working towards a solution and will notify CCA when available.

f. Data Access via API. CCA will have the ability to access Hourly Prices and Subscription data programmatically via API. PG&E will provide HFP Pilot Operational Handbook with instructions on how to use the API and its services.

g. CCA Enrollment Bonus Report. PG&E will issue an annual CCA Enrollment Bonus Report in the first quarter for the previous year, detailing the customer Enrolled Load per SAID along with the corresponding payment amounts.

D. Customer Billing. For the OOTB and Hybrid options, PG&E will provide billing-related functions for participating CCAs. For the Custom option, the CCA is responsible for all contracting costs with third-party vendors selected by PG&E for the purpose of the HFP Pilot, as well as operations necessary for participating in HFP Pilots. PG&E will facilitate the initial coordination with the CCA and PG&E's third-party vendors on the implementation of the Custom option. PG&E will provide all HFP Pilots participants, including CCA customers, with the HFP shadow bill on a monthly basis. The HFP shadow bill will track the HFP Pilot participant's performance on the HFP rate, both incremental (i.e., reflecting performance during the billing cycle) and cumulative (i.e., reflecting performance since customer's enrollment on the HFP Pilot). The presentation of the customer's incremental and cumulative shadow bill comparison between the HFP rate and the customer's OAT will be communicated to the customer as one total amount, which will not differentiate between the CCA generation savings, if any, and the PG&E distribution savings, if any. PG&E will be responsible for sending the customer the 12-month cumulative bill comparison which establishes the customer HFP Credit, if any. Consistent with Advice Letter E-7222-E-B, PG&E will work with the CCA on the message to the CCA's customers.

E. Calculation to avoid double compensation. The HFP Pilots are subject to Commission requirements to avoid double compensation for customers that are concurrently enrolled in demand response programs for which dual participation is permitted. For PG&E programs, such as the ELRP program, PG&E will be responsible to apply the methodology and perform the calculations as required to avoid double compensation.

F. Customer Specific Information. To ensure compliance with California privacy laws, each participating customer must accept the HFP Pilot customer participation terms and conditions. Pursuant to the HFP Pilot customer participation terms and conditions, which the customer must accept to be eligible to participate in the selected HFP Pilot, the CCA customer consents to PG&E providing to the customer's CCA the customer's identity, usage or meter data and other information involving the customer's participation in the relevant HFP Pilot (Customer Data). The Customer Data will be available to the customer's CCA on a monthly basis in the HFP Report, unless and until the customer revokes such consent and ceases to participate in the HFP Pilot and all data on the final bill period of the customer's participation has been delivered to the CCA.

G. Customer Outreach. PG&E is to establish a process to identify and share with CCAs unbundled customers SAIDs that are not enrolled in PG&E load management programs and are eligible for HFP pilot. This will improve HFP CCA outreach to its unbundled customers, as their LSE in the pilot (AL 7222-E). PG&E will engage CCA for approval to conduct HFP Pilot outreach to CCA's unbundled customers, either via PG&E, PG&E's vendor and/or participating ASPs. CCA will be responsible for documenting any outreach restrictions in cases where CCA decides to limit/prevent outreach to eligible CCA customers.

H. Custom Solution Support. PG&E will provide PG&E's vendor (i.e., GridX, Polaris) contact information to interested CCA and will participate in CCA/vendor meetings as determined by CCA to enable expedient vendor contract negotiations and implementation. Initial coordination between the CCA and PG&E's third-party vendors will be assisted by PG&E within 30 days after the Effective Date. CCA is solely responsible for the project management and cost of the Custom Option implementation.

IV. TERM

The term of this Agreement shall commence as of the Effective Date and shall continue in effect until the end of the HFP Pilots, as indicated below, unless earlier terminated as provided in Section V.

- Expanded Pilot #1: December 31, 2027. Participating customers may receive their last HFP shadow bill and HFP Credit(s) several months later. Per AL 7222, no new enrollments will occur after May 31, 2027.
- Expanded Pilot #2: December 31, 2027. Participating customers may receive their last HFP shadow bill and HFP Credits several months later. Per AL 7222, no new enrollments will occur after May 31, 2027.
- Phase 2 of the Vehicle to Grid (VGI) Pilots: until the CPUC authorized budget is exhausted. Participating customers may receive their last HFP shadow bill and HFP Credits several months after the pilot ends.

V. TERMINATION

A. CCA Termination. The CCA may terminate participation in any of the selected HFP pilots with 90 days advance notice.

B. Termination for Default. Each of the Parties may immediately terminate this Agreement upon written notice to the other Party due to breaches of any material obligation under this Agreement. If the violating Party fails to cure such breach within thirty (30) calendar days after receiving written notice of the breach or such additional time as may be reasonably necessary to cure such breach, provided violating Party informs the other Party of its intention to cure the breach and provides an estimated schedule for curing such breach, and then continues diligently in its efforts to cure such breach. Violating party must notify the other Party upon curing the identified breach.

C. Termination at CPUC Direction. PG&E may terminate this Agreement upon 90 days written notice to CCA if the CPUC orders the termination of an HFP Pilot or this Agreement or upon a different timeline if directed in a CPUC order. PG&E shall confer with the CCA prior to termination to discuss the timing of such termination and any necessary work to conclude the pilot and within the timeframe for termination provided in such order.

D. Effect of Termination. Upon termination of this Agreement, the CCA customers enrolled in the HFP Pilots will be notified of their unenrollment from the pilot at the determined termination date. The customers will receive their final HFP shadow bill reflecting any HFP credits calculated up to the termination date.

VI. INDEMNIFICATION

A. Mutual Indemnification. To the fullest extent permitted by law, each Party ("Indemnifying Party") shall indemnify, defend and hold harmless the other Party, and its parent company, subsidiaries, affiliates and their respective shareholders, officers, directors, employees, agents, representatives, successors and assigns as applicable (collectively, the "Indemnified Parties"), from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses, including without limitation reasonable attorneys' fees and costs, resulting from (a) any breach of the representations, warranties, covenants and obligations of the Indemnifying Party under this Agreement, (b) any act or omission of the Indemnifying Party, whether based upon its negligence, strict liability or otherwise, in connection with the performance of this Agreement, or (c) any third party (including customer) claims of any kind, whether based upon negligence, strict liability or otherwise, arising out of or connected in any way to the Indemnifying Party's performance or nonperformance under this Agreement.

B. Defense of Claim. If any Claim is brought against the Indemnified Parties, the Indemnifying Party shall assume the defense of such Claim, with counsel reasonably acceptable to the Indemnified Parties, unless in the opinion of counsel for the Indemnified Parties a conflict of interest between the Indemnified Parties and the Indemnifying Party may exist with respect to such Claim. If a conflict precludes the Indemnifying Party from assuming the defense, then they shall reimburse the Indemnified Parties on a monthly basis for the Indemnified Parties' reasonable defense costs through separate counsel of the Indemnified Parties' choice. If Indemnifying Party assumes the defense of the Indemnified Parties with acceptable counsel, the Indemnified Parties, at their sole option and expense, may participate in the defense with counsel of their own choice without relieving the Indemnifying Party of any of its obligations hereunder.

C. Survival. Both Parties' obligations in this Section VI shall survive the expiration or termination of this Agreement.

VII. CONFIDENTIALITY

A. Confidentiality. Neither Party shall disclose any Confidential Information obtained pursuant to this Agreement to any third party, without the express prior written consent of the other Party. Notwithstanding the prior sentence, each Party may share Confidential Information with consultants and billing agents, subject to Non-disclosure Agreement, for the purpose of fulfilling its obligations under this Agreement. As used herein, the term "Confidential Information" means proprietary business, financial and commercial information pertaining to PG&E or CCA (which has been clearly marked as being "CONFIDENTIAL" in writing), customer names and other information related to customers, including energy usage data (Customer Personal Information), Confidential Information shall not include: (a) information known by a Party prior to obtaining the same from the other Party; (b) information in the public domain at the time of disclosure by the Party; (c) information obtained by a Party from a third party who did not receive the same, directly or indirectly, from the other Party; (d) information approved for release by express prior written consent of an authorized representative of the Party; or (e) any information that CCAs have access to independently from this agreement (e.g., the CPUC Resolution E-4013 (2006) report which includes customer data).

B. Use of Confidential Information. Each Party hereby agrees that it, and its consultants and/or billing agents, shall use the Confidential Information solely for the purpose of the HFP Pilots or where otherwise authorized by law and regulations. Each Party agrees to use at least the same degree of care the Party uses with respect to its own proprietary or confidential information, which in any event shall result in a reasonable standard of care to prevent unauthorized use or disclosure of the Confidential Information.

C. Authorized Disclosure. Notwithstanding any other provisions of this Section, a Party may disclose any of the Confidential Information in the event, but only to the extent, that, the Party is required or authorized to do so by the disclosure requirements of any law, rule, regulation, including requests under the California Public Records Act, or any order, decree, subpoena or ruling or other similar process of any court, governmental agency or regulatory authority. Prior to making or permitting any such disclosure, the Party shall provide the other Party with prompt written notice of any such requirement so that the other Party may seek a protective order or other appropriate remedy.

D. Term. The confidentiality provisions set forth in this Section shall remain in full force and effect with respect to any Confidential Information unless such disclosure is otherwise permitted by law and provided, further, that such confidentiality provisions shall remain in full force and effect with respect to any Customer Personal Information in perpetuity.

E. Remedies. The Parties acknowledge that the Confidential Information is valuable and unique, and that damages would be an inadequate remedy for breach of this Section and the obligations of the Parties are specifically enforceable. Accordingly, the Parties agree that in the event of a breach or threatened breach of this Section, the impacted Party shall be entitled to seek an injunction preventing such breach. Any such relief shall be in addition to, and not in lieu of, monetary damages or any other legal or equitable remedy available.

VIII. GENERAL TERMS

A. Limitation of Liability. The Parties shall not be liable to each other for any damages caused by actions taken by the other to comply with any order or decision of the CPUC regarding the conduct or implementation of the HFP Pilots Both PG&E and CCA further agree that each Party shall not be liable to the other Party for any damages to any customer the other caused by, or resulting from (i) any non-compliance with the requirements and responsibilities in the HFP Pilots, this Agreement and associated legal and regulatory requirements, (ii) non-performance of any commitment to the customer or (iii) any acts, omissions or representations made in soliciting customers for services or performing its functions as a load serving entity in the HFP Pilots.

B. Notice. Any formal notice, request, or demand required or permitted under this Agreement shall be given in writing by PG&E and CCA, and shall be either (a) mailed by first-class mail, (b) mailed by registered, certified, (c) mailed by overnight mail, (d) delivered by hand, or (e) e-mailed with confirmation to the other Party as follows or as otherwise expressly agreed to by the Parties:

To CCA:

____
____
____
E-mail:________________________
Phone:________________________

To PG&E:

Oriana Tiell
300 Lakeside Dr.
Oakland, CA 94612-3534
E-mail: oriana.tiell@pge.com
Phone: 415.577.0004

C. Assignment. This Agreement, and the rights and obligations granted and/or obtained by a Party hereunder, shall not be further transferred or assigned by the Party without the prior written consent of the other Party. Any assignment in violation of this Section shall be void.

D. Dispute Resolution and Choice of Law. This Agreement or to the performance of a Party's obligations hereunder shall be reduced to writing and referred to the other Party's designated representative for resolution. The Parties shall be required to meet and confer in an effort to resolve any such dispute. If the Parties are unable to resolve such dispute, except for matters and disputes with respect to which the CPUC is the proper venue for dispute resolution pursuant to applicable law or this Agreement, the state courts located in San Francisco, California shall constitute the sole proper venue for resolution of any matter or dispute hereunder. The Parties submit to the exclusive jurisdiction of such courts with respect to such matters and disputes. Each Party bears their own attorneys' fees and costs associated with any such dispute.

E. Waiver. Any failure or delay by either Party to exercise any right, in whole or part, shall not be construed as a waiver of the right to exercise the same, or any other right.

F. CPUC Jurisdiction. This Agreement shall be subject to all legal and regulatory requirements applicable to HFP Pilots, including, without limitation, orders, changes or modifications as the CPUC may, from time to time, direct.

G. Entire Agreement; Amendments. This Agreement sets forth the entire understanding of the Parties as to the CCA's participation in the HFP Pilots, and supersedes any prior discussions, offerings, representations or understanding (whether written or oral), and shall only be superseded by an instrument in writing executed by both Parties. This Agreement shall not be modified by course of performance, course of conduct or usage of trade.

H. Survival. Notwithstanding the expiration or termination of this Agreement, the Parties shall continue to be bound by the Agreement's provisions which, by their nature, survive completion or termination.

J. Authority. Any individual executing this Agreement represents and warrants hereby that he or she has the requisite authority to enter into this Agreement on behalf of such party and bind the party to the terms and conditions of this Agreement.

K. Severability. If any provision of this Agreement is held invalid by a court with jurisdiction over the Parties, such provision will be deemed to be restated to reflect as nearly as possible the original intentions of the Parties in accordance with applicable law, and the remainder of this Agreement will remain in full force and effect.

L. Counterparts and Electronic Signatures. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument. Executed counterparts of this Agreement may be delivered by email in a scanned counterpart portable document format (PDF). On such confirmed delivery, the signatures in the PDF data file shall be deemed to have the same force and effect as if the manually signed counterparts have been delivered to the other party in person. The Parties consent to the use of electronic signatures via DocuSign to execute this Agreement.

M. Headings. The headings contained in this Agreement are solely for the convenience of the Parties and shall not be used or relied upon in any manner in the construction or interpretation of this Agreement.

IN WITNESS WHEREOF, the authorized representatives of PG&E and CCA have executed this Agreement as of the respective date set forth below, made effective as of the Effective Date.

(CCA Name)		**PACIFIC GAS AND ELECTRIC COMPANY**
(Signature)		(Signature)
(Type/Print Name)		(Type/Print Name)
(Title)		(Title)
(Date)		(Date)
(Signature as applicable)		
(Type/Print Name)		
(Title)		
(Date)		

Approved as to form