

Regulatory Filings

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

Application of Pacific Gas and Electric
Company for Approval of Its Billing
Modernization Initiative

(U 39 M)

Application 24-10-014
(Filed October 23, 2024)

**JOINT REPLY BRIEF OF PACIFIC GAS AND ELECTRIC
COMPANY (U 39 M) AND THE JOINT COMMUNITY CHOICE
AGGREGATORS**

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Dated: August 13, 2026

**BEFORE THE PUBLIC UTILITIES COMMISSION
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**I. IMPLEMENTING C2M WILL ENABLE ADDITIONAL BENEFITS FOR CCAS
AND CCA CUSTOMERS**

CalAdvocates, SBUA, and TURN do not engage with the need for improvements to PG&E's billing system or the benefits that will flow to customers once the BMI is completed. No party can dispute that the legacy billing system's patchwork of systems are decades old and are simply not capable of keeping up with the complexity of modern rates. A modern billing system, including a modular rate engine, will offer the functionality necessary to implement complex rates, reduce risk associated with the aging billing systems, and benefit all customers. In addition, a modern billing system like C2M will enable PG&E to provide necessary features and data reporting to all CCAs that will benefit CCA customers and support competition. With these considerations in mind, the Joint CCAs support the capital expenditure and expense forecasts set forth in the Partial Settlement Agreement.¹

In addition to providing billing services for the bundled customers that it serves, PG&E provides metering, billing, collection, and customer service to CCA customers. Currently, more than half of PG&E's customers are unbundled and receive service from CCAs, and according to the Joint CCAs further CCA expansion is expected in the next few years.² Currently, PG&E's outdated legacy billing systems impose functional limitations on how data can be shared and

¹ The Partial Settlement Agreement sets forth costs for the BMI of \$586,614 in capital and \$81,595 in expense, as well as costs associated with the settlement agreement proposals of \$21,000 in capital and \$3,000 in expense.

² Direct Testimony of Kyra J. Coyle on Behalf of the Joint Community Choice Aggregators in PG&E's Billing Modernization Initiative (Errata Jul. 1, 2025), pp. 6:25-26 – 7:5.

how bill contents and the billing process are managed. Importantly, the features identified in Sections 3.3(a)(iv), 3.3(d), 3.4(a), 3.4(b), 3.4(d), 3.4(f), and 3.4(g) of the Partial Settlement Agreement can be enabled only if PG&E is able to implement C2M, or an end-state billing system with substantially similar capabilities.³ The end-state billing system will enable these features that will benefit CCAs and CCA customers, as well as contribute to a better billing experience for all customers.

While CalAdvocates, SBUA, and TURN take issue with cost and other aspects of the BMI, they cannot reasonably dispute that the current legacy billing systems are out-of-date and have functional shortcomings. PG&E has provided evidence supporting the benefits that will result from the implementation of C2M,⁴ and the implementation of C2M (or a comparable end-state system) is also necessary groundwork for the implementation of some aspects of the Partial Settlement Agreement.

³ Section 3.1 of the Partial Settlement Agreement.

⁴ See PG&E Ex-01, p. 6-12, line 11 to p. 6-12, line 16; p. 6-13, Table 6-4; p. 6-28, lines 3-4; p. 6-30, line 32 to p. 6-31, line 3.

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August 12, 2026

Bay Area Air District
375 Beale Street, Suite 600
San Francisco, CA 94105

RE: Draft Rule Language for Regulation 9, Rule 6 Amendments (Small Water Heaters)

The undersigned Bay Area Community Choice Aggregators ("Joint-CCAs") submit the following comments to the Bay Area Air District ("Air District") regarding the draft language ("Draft Language") for Regulation 9, Rule 6 ("Rule 9-6") published on July 13, 2026. The Joint-CCAs appreciate the opportunity to comment and commend Air District staff for the technical care and responsiveness reflected in the Draft Language.

The Joint-CCAs thank the staff and the Board for their consideration of the exemption concepts the Joint-CCAs raised in prior comment letters. Specifically, in comments submitted regarding the CONCEPTS FOR RULE 9-6 AMENDMENTS: Affordability and Availability Considerations for Zero NOx Small Water Heaters Concept Paper, the Joint-CCAs identified space-constrained installations, affordability protections, and a clear end date for temporary exemptions as the three issues most likely to determine whether Rule 9-6 is implemented smoothly and equitably. The Draft Language responds to all three. That responsiveness matters to the contractors, distributors, and program administrators who will carry out this transition and builds confidence in the process among customers.

Also, the Joint-CCAs appreciate the extension of the compliance deadline for small water heaters to January 1, 2028. The additional year allows the market to continue maturing with the help of the Joint-CCAs' evolving suite of customer incentives and allows contractors and distributors to gain experience with heat pump water heaters and to adjust stocking practices. The extension also creates more opportunities for vital public education to teach customers about this rule now rather than during an emergency replacement. Finally, the extension also gives the Air District the necessary time to design, test, and communicate the exemption process itself.

Low-Income Flexibility Measures and Clear End Dates

The Joint-CCAs agree that lower-income families must not be overly burdened by Rule 9-6 and that the Air District is not prepared to operate an income verification system efficiently. However, the Joint-CCAs believe that the suggested provision in the Draft Language regarding the low-income flexibility measure will be difficult to properly implement and may lead to an inappropriate level of exemptions. Many customers and contractors may not be prepared to accurately calculate their "housing cost-burden." The Joint-CCAs believe that an attestation that the customer's household income is below 80% of the area's median income would be more straightforward and would provide relief to the intended population. The joint-CCAs further support ensuring the

benefits of electrification ultimately support all customers, including low-income customers.

The Joint-CCAs support the income-based exemption in the Draft Language and encourage continued monitoring of installation costs, product availability, and customer impacts as the market develops. The Joint CCAs also continue to support defined sunset dates for temporary exemptions, which provide market certainty, encourage early product innovation, and support planning by manufacturers, contractors, distributors, and program administrators. Consistent with the Joint CCAs' prior comments on the Concept Paper, the process to access any exemption should be fast, available in multiple languages, and simple with which to comply.

The Joint-CCAs are encouraged by the thoughtful consideration Air District staff have given to the issues raised during the implementation of Rule 9-6. The Joint-CCAs remain committed to helping customers and communities benefit from cleaner, healthier technologies and look forward to continued collaboration with the Air District and other partners to support this transition.

Sincerely,

DocuSigned by:

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Grace Kay
 Manager, Regulatory & Legislative
 Affairs, Power Enterprise



Signed by:

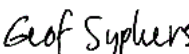
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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue
Electric Integrated Resource Planning and
Related Procurement Processes.

R.20-05-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON
ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON
ADDITIONAL PROPOSAL FOR A RELIABLE AND CLEAN POWER
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August 14, 2026

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SUMMARY OF RECOMMENDATIONS¹

- Option 3 should be rejected because establishing binding procurement requirements based on uncertain assumptions used in the PSP that may not align with market realities risks distorting the market, creating the potential for supplier market power, and raising ratepayer costs;
- Option 1 + CES should be adopted because a procurement framework based on total needs including new plus existing resources will better align reliability and policy procurement needs with an efficient and affordable procurement environment;
- To the extent the Commission moves forward with a new resource procurement requirement framework (which CalCCA does not support), only Option 2 should be considered, but with the following significant modifications to ensure new resource procurement requirements are feasible, affordable, and equitable:
 - Establish technology neutral procurement requirements using SOD accounting;
 - Remove procurement buffers to avoid unnecessary and costly over-procurement;
 - Allocate needs associated with data center loads through a separate, milestone-based process that accounts for the significant uncertainty associated with these loads;
 - Allocate needs based on each LSEs' load ratio share in the year of need to ensure allocations accurately reflect each LSEs' contributions to the need;
 - Provide LSEs with indicative need allocations beyond the five-year compliance horizon to support long-term procurement and planning;
 - Provide LSE-specific need allocations confidentially to protect market-sensitive information and avoid impairing LSEs' negotiating positions;
 - Confirm that excess LSE procurement is eligible to satisfy future RCPPP requirements;
 - Ensure RCPPP products and obligations are sufficiently transactable to allow LSEs to manage their portfolios and meet requirements cost-effectively;
 - Align RCPPP reporting and compliance obligations with realistic procurement timelines;
 - Adopt a "good faith efforts" standard that accounts for circumstances outside an LSE's control that affect its ability to comply; and
 - Assess penalties only for COD deficiencies to avoid imposing duplicative penalties for the same underlying deficiency.

¹ Acronyms used herein are defined in the body of this document.

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Order Instituting Rulemaking to Continue
Electric Integrated Resource Planning and
Related Procurement Processes.

R.20-05-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S COMMENTS ON
ADMINISTRATIVE LAW JUDGE’S RULING SEEKING COMMENTS ON
ADDITIONAL PROPOSAL FOR A RELIABLE AND CLEAN POWER
PROCUREMENT PROGRAM**

California Community Choice Association² (CalCCA) submits these comments pursuant to the *Administrative Law Judge’s Ruling Seeking Comments on Additional Proposal for a Reliable and Clean Power Procurement Program*³ (Ruling), dated June 23, 2026, and the *Email Ruling Partially Granting Joint Investor-Owned Utilities’ Request for an Extension of Time for Comments in Response to Administrative Law Judge’s Ruling Seeking Comments on Additional Proposal for a Reliable and Clean Power Procurement Program*,⁴ dated July 13, 2026.

I. INTRODUCTION

Roughly 7,000 megawatts (MW) of new resource installed capacity must interconnect every year in California to meet the build level necessary to meet the requirements of Senate Bill

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, 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, Valley Clean Energy, and WestLight Energy.

³ *Administrative Law Judge’s Ruling Seeking Comments on Additional Proposal for a Reliable and Clean Power Procurement Program*, Rulemaking (R.) 20-05-003 (June 23, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M609/K223/609223925.PDF>.

⁴ *Email Ruling Partially Granting Joint Investor-Owned Utilities’ Request for an Extension of Time for Comments in Response to Administrative Law Judge’s Ruling Seeking Comments on Additional Proposal for a Reliable and Clean Power Procurement Program*, R.20-05-003 (July 13, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M609/K223/609223925.PDF>.

100.^{5,6} Beyond state-level goals, many community choice aggregators (CCA) have accelerated greenhouse gas (GHG) reduction targets adopted by their governing boards. CCAs are committed to developing new resources to accelerate the state’s clean energy buildout and support California’s reliability goals. A range of technologies are being explored to accomplish these objectives. Indeed, as of November 19, 2025, California CCAs have secured 21+ gigawatts (GW) of new build clean energy resources through long-term power purchase agreements (PPA).⁷

These state and local policies, along with ongoing procurement orders from the California Public Utilities Commission (Commission), have driven significant demand in the market for new resources. Concurrently, market supply has remained constrained, due to several barriers to bringing new supply online quickly and affordably. These barriers include supply chain issues, permitting challenges, extended interconnection timelines and constrained transmission plan deliverability (TPD), federal policy changes, and other barriers. Experience with procurement orders in Decision (D.) 19-11-016⁸ and D.21-05-035⁹ (the mid-term reliability (MTR) Order) demonstrates that procurement mandated on expedited timelines exacerbates these challenges and in turn negatively impacts affordability. For this reason, CalCCA has been supportive of the Commission’s efforts to develop a Reliable and Clean Power Procurement Program (RCPPP) to

⁵ Senate Bill 100 (SB 100) Ch. 312, Stats. 2018 (DeLeon), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100. .

⁶ The 2021 SB 100 Joint Agency Report finds a build out of roughly 175,000 MW is needed between 2021 and 2045 to meet SB 100 targets. 175,000 MW built over 24 years amounts to roughly 7,000 MW per year. See 2021 SB 100 Joint Agency Report (Mar. 2021) at 10: <https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349>.

⁷ CalCCA. “California CCAs Achieve Procurement Milestone – Secure 21+ Gigawatts of New-Build Clean Energy Resources” *Cal-CCA.org*, 19 Nov. 2025, <https://cal-cca.org/california-ccas-achieve-procurement-milestone-secure-21-gigawatts-of-new-build-clean-energy-resources/>.

⁸ D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, R.16-02-007 (Nov. 7, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF>.

⁹ D.21-05-035, *Order Modifying Decision 20-04-020 and Denying Rehearing of the Decision, As Modified*, Application 17-01-013, et al. (May 20, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M385/K269/385269751.PDF>.

ensure the Integrated Resource Planning (IRP) process balances reliability, GHG reduction, and customer affordability through orderly and predictable procurement requirements.¹⁰

Unfortunately, the Ruling’s additional proposal, referred to herein as “Option 3,” would continue the push on the demand-side lever without any attempts to improve the availability of supply. Option 3 would make the Preferred System Plan (PSP) portfolio, which is currently developed to inform transmission development needed to meet policy objectives, a “binding” procurement obligation for LSEs. Doing so would establish rigid compliance requirements based on planning assumptions that may differ from market realities, with no consideration of whether the ordered procurement is feasible given market supply. It would then allocate requirements to all load-serving entities (LSE) without consideration of load forecast uncertainty or individual LSE portfolio needs. It would also deviate significantly from existing procurement requirements to comply with the Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) programs, adding new compliance requirements and costs for needs that are also addressed by these programs. Requiring procurement without regard to actual LSE need, existing compliance obligations, or market conditions risks imposing significant and potentially unnecessary costs on ratepayers. Option 3 could therefore increase customer rates without a corresponding demonstration that additional procurement is needed or achievable, compromising the Commission’s RCPPP program design principle of affordability. In summary, Option 3 would convert the PSP into a highly prescriptive, continuously recurring procurement mandate without

¹⁰ *California Community Choice Association’s Comments on Administrative Law Judge’s Ruling Seeking Comments on Staff Paper On Procurement Program*, R. 20-05-003 (Dec. 12, 2022), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K887/499887293.PDF>; and *California Community Choice Association’s Comments on Administrative Law Judge’s Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF>.

resolving several foundational questions about modeling accuracy, need allocation, load forecast uncertainty, and accreditation.

Option 3 is inferior to both of Energy Division's previously proposed options. Option 1 would determine the total system need for the compliance period and allow LSEs to meet this need with a combination of *new and existing resources*. Option 2 would establish a new resource need and require LSEs to meet this need with *new resource procurement*. CalCCA strongly recommends the Commission adopt Option 1 plus a Clean Energy Standard (CES) because it: (1) provides LSEs the flexibility necessary to procure cost-effectively; (2) ensures proper planning for new *and* existing resource needs; (3) enables LSEs to manage load forecast uncertainty; (4) accounts for LSEs' prior procurement decisions and individual portfolio needs; (5) and aligns with existing RA and RPS compliance requirements, as described in Section IV., herein. To the extent the Commission moves forward with a new resource procurement requirement framework (which CalCCA does not support), only Option 2 should be considered. While Option 2 provides a more workable framework than Option 3, it still requires significant modifications to ensure new resource procurement requirements are feasible, affordable, and equitable.

In summary:

- Option 3 should be rejected because establishing binding procurement requirements based on uncertain assumptions used in the PSP that may not align with market realities risks distorting the market, creating the potential for supplier market power, resulting in increased ratepayer costs;
- Option 1 + CES should be adopted because a procurement framework based on total needs including new plus existing resources will better align reliability and policy procurement needs with an efficient and affordable procurement environment;
- To the extent the Commission moves forward with a new resource procurement requirement framework (which CalCCA does not support), only Option 2 should be considered, but with the following significant modifications to ensure new resource procurement requirements are feasible, affordable, and equitable:
 - Establish technology neutral procurement requirements using slice-of-day (SOD) accounting;

- Remove procurement buffers to avoid unnecessary and costly over-procurement;
- Allocate needs associated with data center loads through a separate, milestone-based process that accounts for the significant uncertainty associated with these loads;
- Allocate needs based on each LSEs' load ratio share in the year of need to ensure allocations accurately reflect each LSEs' contributions to the need;
- Provide LSEs with indicative need allocations beyond the five-year compliance horizon to support long-term procurement and planning;
- Provide LSE-specific need allocations confidentially to protect market-sensitive information and avoid impairing LSEs' negotiating positions;
- Confirm that excess LSE procurement is eligible to satisfy future RCPPP requirements;
- Ensure RCPPP products and obligations are sufficiently transactable to allow LSEs to manage their portfolios and meet requirements more cost-effectively;
- Align RCPPP reporting and compliance obligations with realistic procurement timelines;
- Adopt a "good faith efforts" standard that accounts for circumstances outside an LSE's control that affect its ability to comply; and
- Assess penalties only for commercial operation date (COD) deficiencies to avoid imposing duplicative penalties for the same underlying deficiency.

II. OPTION 3 SHOULD BE REJECTED BECAUSE ESTABLISHING BINDING REQUIREMENTS BASED ON THE PSP RISKS DISTORTING THE MARKET, ENABLING SUPPLIER MARKET POWER, AND INCREASING RATEPAYER COSTS

CalCCA has long supported the Commission's efforts to develop RCPPP given the shortcomings associated with the order-by-order approach.¹¹ These shortcomings include but are not limited to unpredictable requirements, limited time and flexibility to comply, and the flooding of a supply-constrained market with new demand to comply with the new order. Distortion of the market can then occur, introducing the potential for suppliers to exercise market

¹¹ See *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Staff Paper On Procurement Program*, R. 20-05-003 (Dec. 12, 2022), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K887/499887293.PDF>; and *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF>.

power and raise ratepayer costs. As the Commission stated in its 2022 Staff Options paper, the RCPMP should achieve economically efficient procurement and mitigate risks of market power.¹² However, Option 3 deviates significantly from the Commission's RCPMP principles and the previous options under consideration by subjecting LSEs and their customers to many of the same challenges associated with the order-by-order approach.

In summary, and as explained below, Option 3 should be rejected because it:

- Bases procurement requirements on planning assumptions that may not reflect market realities;
- Imposes rigid compliance requirements that risk creating market inefficiencies and unnecessarily increasing procurement costs ultimately borne by ratepayers;
- Increases demand for a constrained pool of resources without addressing how to lower barriers to new resource development;
- Fails to account for load forecast uncertainty and individual LSE portfolio needs;
- Misaligns with other procurement and compliance requirements, risking duplicative or unnecessary procurement costs without incremental benefit;
- Fails to adequately plan for the orderly retirement or account for repowers of existing resources; and
- Disincentivizes prudent planning and procurement of long-lead time (LLT) resources.

A. Option 3 Bases Procurement Requirements Upon Planning Assumptions That May Not Reflect Market Realities

Individual LSE IRPs and the Commission's PSP are based upon assumptions about resource cost, availability, and other factors. No matter how well-informed the assumptions may be, markets evolve quickly, and actual resource availability and cost may differ significantly from the assumptions underlying the PSP. As demonstrated by the analysis in Section III., below, there are multiple pathways to achieving reliability and GHG-reduction goals, and the most cost-effective pathway depends heavily on the assumptions used. The portfolios developed by the

¹² *Reliable and Clean Power Procurement Program Staff Options Paper*, R.20-05-003 (Sept. 2022) at 8, <https://docs.epuc.ca.gov/PublishedDocs/Efile/G000/M496/K684/496684997.PDF>.

Renewable Energy Solutions model (RESOLVE) model are highly sensitive to those assumptions, such that even modest changes can significantly alter the type and quantity of resources selected.

Option 3 sets new resource procurement requirements for reliability and clean energy needs consistent with the PSP within a range. While CalCCA appreciates the Commission’s desire to create a “bridge to connect the [IRP] required by Senate Bill (SB) 350 (Stats. 2015, Ch. 547), transmission planning, and LSE procurement,”¹³ strictly mandating procurement of the PSP, even within a range, will not result in the most cost-effective path to meet reliability and clean targets. The PSP is based upon forward planning assumptions about resource cost and availability that may not materialize in the market when LSEs are procuring.

B. The Rigid Compliance Requirements in Option 3 Will Create Market Inefficiencies and Increase Costs

In the Staff Proposal put forward in 2025, Energy Division recognized that the options for RCPPP development “should allow market participants to choose the best procurement to match their resource preferences and risk tolerance.”¹⁴ However, Option 3 contradicts this principle by constraining LSEs’ abilities to make the best procurement choices based on market realities. Option 3 would create an unnecessarily rigid compliance framework that limits the ability of market signals to drive the most efficient mix and timing of resource procurement and fails to adapt to evolving system needs, including changes in anticipated load growth. As described above, specific resources and resource attributes may be included in the PSP based on the assumptions used to develop the PSP. In the market, however, these resources/attributes may

¹³ Ruling, at 5.

¹⁴ *Integrated Resource Planning Workshop: Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (May 16, 2025) at 11, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/rcppp/rcppp-workshop-slides-redlined.pdf>.

not be cost-effective, commercially ready, or available in the volumes at the times required by the procurement order. Resource- or attribute-specific orders limit LSE flexibility and create opportunities for developers to raise costs or exert market power, especially when such resource attributes can only be met by a very limited pool of technologies. These overly prescriptive requirements also fail to acknowledge the reality of the statewide interconnection queues, which show the supply of clean-firm resources to be near or less than the required volumes in the PSP.

Option 3 effectively enforces a resource-specific procurement obligation, allowing for limited substitution of resources from those defined in the PSP. This violates long-held Commission principles that procurement should be technology-neutral, so long as the mix of resources meets reliability and GHG goals, and is balanced with ratepayer affordability. In D.19-11-016, the Commission stated, “[l]ike most parties, we support solicitations being conducted in an all source manner, allowing all types of resources to count toward the 3,300 MW requirements we implement in this decision.”¹⁵ More recently, the Commission reemphasized its preference for technology neutrality, but made an exception to this based on the circumstances specific to grid conditions at that time through D.21-06-035.¹⁶ The MTR Order sought to preserve LSE procurement flexibility by defining the resource “attributes” that LSEs were required to procure (*e.g.*, clean firm resources), rather than prescribing resource types or technologies. However, the way the MTR Order defined such attributes means that LSEs have a very limited pool of suppliers that can fulfill the requirement. As seen with the MTR Order, resource- and/or attribute-specific

¹⁵ D.19-11-016, at 43.

¹⁶ D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability* (2023-2026), R.20-05-003 (June 30, 2021), at 35, “While we generally prefer to be technology-neutral, there are instances where too much of a least-cost option leads to its own set of challenges. We are facing this situation now due to the confluence of several factors: an abundance of solar energy, the impending loss of a large chunk of nuclear capacity, and the retirement of a number of OTC thermal plants. This means a reduction in the system’s ability to supply firm and/or dispatchable energy when the grid needs it most.”, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF>.

procurement can be challenging and expensive when the supply is constrained and suppliers know their technology is needed to meet compliance requirements.¹⁷

Since the issuance of the MTR Order, the Commission has recognized the challenges associated with this exception and sought to avoid them in RCPMP, stating, “[a] technology agnostic approach leaves competitive market processes to identify the optimal resource types and locations, and is probably appropriate for a large portion of the procurement required to meet SB 100 goals.”¹⁸ It also listed “mitigat[ing] the risks of market power” as an express objective of RCPMP.

It is not clear why the Commission would make a significant change from its prior policy of technology neutrality to an RCPMP that is resource-specific. The Ruling states, “...there is no mechanism in place to compel LSEs procure the necessary diverse resource mix consistent with the overall system needs, even if they are represented in the individual LSE IRPs, rather than simply the lowest cost resources (which are usually, currently, solar and four-hour storage).”¹⁹ However, there are multiple factors that compel LSEs to diversify their portfolios, including but not limited to: (1) their need to reliably serve their customers with clean energy resources; (2) the RA SOD program that puts great value on resources that can provide capacity outside the solar hours; (3) local and community preferences, such as location or technology type; and (4) direction from their governing boards. Indeed, CalCCA reviewed the websites of its members²⁰ dating back to 2018 (with most between 2020 and present), and found 26 solicitations involving

¹⁷ The Commission has had to modify its orders on multiple occasions to accommodate for challenges LSEs face obtaining capacity on the timeline prescribed in the orders. For example, D.23-02-040 and D.24-02-047 provide an extension of time for LSEs to satisfy the LLT resource procurement requirement, given the extremely challenging market conditions impacting the ability for LSEs to comply with the prescriptive attribute-based procurement order.

¹⁸ *Reliable and Clean Power Procurement Program Staff Options Paper*, R.20-05-003 (Sept. 2022) at 8, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K684/496684997.PDF>.

¹⁹ Ruling, at 7.

²⁰ CCA solicitations can be accessed here: <https://cal-cca.org/opportunities/#toggle-id-2>.

15 CCAs (either jointly or individually) that conducted requests for offers (RFO) seeking geothermal resources. In addition, several CCAs have begun working on pre-commercial agreements to demonstrate the continued progress necessary to develop emerging resources and ultimately lead to commercial operation.²¹ As of November 19, 2025, California CCAs have secured 21+ GW of new build clean energy resources through long-term power purchase agreements PPAs for wind, geothermal, demand response, biogas, solar, and storage.²²

Rather than mandating procurement of resources or attributes that may not be available in the quantities or at the costs assumed in the PSP, the Commission should focus on reducing barriers to resource development—including financing challenges, permitting constraints, transmission infrastructure needs, and a lack of available TPD—to increase the supply of viable resources. Then, it should allow market competition to identify the most cost-effective means of satisfying reliability- and policy-driven procurement needs.

C. Option 3 Will Increase Demand for Constrained Resource Pools While Failing to Address Supply-Side Barriers to New Resource Development

The Commission has two primary levers to support clean energy deployment: stimulating demand through its procurement program and enabling supply by proactively planning necessary infrastructure, reducing barriers to project development, and taking other actions that facilitate new resource development. The Commission’s current approach, however, is weighted heavily toward demand-side measures without sufficient corresponding action to expand supply. Unless

²¹ See, e.g., Sonoma Clean Power’s GeoZone initiative (<https://sonomacleanpower.org/geozone>), Clean Energy Alliance’s RFI for Geothermal Energy Projects (https://thecleanenergyalliance.org/cea-2026-rfi-for-geothermal-energy-projects_qa/) resulting in four exclusive Letters of Intent (<https://thecleanenergyalliance.org/cea-further-geothermal-energy/>), and Clean Power Alliance’s 2026 Clean Energy Innovation Solicitation for Emerging Technologies (<https://cleanpoweralliance.org/innovation-solicitation/>).

²² See Cal-CCA.org, “California CCAs Achieve Procurement Milestone – Secure 21+ Gigawatts of New-Build Clean Energy Resources” (Nov. 19, 2025), <https://cal-cca.org/california-ccas-achieve-procurement-milestone-secure-21-gigawatts-of-new-build-clean-energy-resources/>.

this imbalance is addressed, the Commission will create demand for products that cannot be developed in sufficient quantities or within the required timelines to satisfy compliance obligations. The resulting supply constraints could reduce competition, increase opportunities for suppliers to exert market power, and ultimately increase ratepayer costs.

This supply and demand imbalance is already causing problems for LSEs. The Commission recently issued a 6,000 MW procurement order in which at least one quarter of the total obligation must be met by clean-firm resources or long-duration energy storage (LDES).²³ While there are multiple technologies that can meet LDES (*e.g.*, lithium based, pumped hydro, compressed air, etc.), the Commission defined clean firm as having a capacity factor of at least 80 percent and not use-limited. With the currently available clean technologies, this “resource attribute” can only be met by geothermal or biomass resources. At present, there is less than 65 MW of geothermal and 0 MW of biomass, the only technologies likely eligible for the clean-firm category, in the CAISO interconnection queue.²⁴ Without an adequate supply of resources capable of satisfying the Commission’s procurement orders or future RCPPP requirements, competition will be constrained, making it extremely challenging and expensive for LSEs to satisfy their requirements.

²³ D.26-02-057, *Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process*, R.25-06-019 (Feb. 26, 2026), Ordering Paragraph (O¶) 2, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M601/K777/601777006.PDF>.

²⁴ The CAISO Queue Cluster 16 study process is scheduled to begin in 2027 and take the entire year. This is followed by the interconnection facility study in 2028 with generator interconnection agreements negotiated and completed by December 2028. This would leave little time for a geothermal resource to meet a 2032 commercial operation date even without slippage of any of the study process dates. *See* CAISO Final Proposal Cluster Schedule, Interconnection Process Enhancements: <https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalProposalClusterSchedule-InterconnectionProcessEnhancements2023Track2.pdf>.

D. Option 3 Fails to Accommodate for Load Forecast Uncertainty and Individual LSE Portfolio Needs

Option 3 will also continue the practice of allocating new resource needs to LSEs based on load-ratio share, ignoring load forecast uncertainty and individual LSE portfolio needs. With the introduction of new demand from data centers, load growth projections have become increasingly uncertain. Requiring LSEs to contract 100 percent of their needs three years forward based upon load ratio share fails to allow LSEs to manage this uncertainty. It also fails to allow the Commission to adequately modify its orders based on new load data. This will likely result in an unfair and inaccurate allocation of needs across LSEs, increasing costs to ratepayers.

This is because Option 3 will identify the total new resource need at one snapshot in time, allocate it to LSEs pro-rata based upon their load ratio share, and will not evolve as the load forecast changes. While the Ruling states that LSEs can transact resources to accommodate for such changes, this is an insufficient solution to a potentially significant problem based on the size and discrete nature of large loads driving a significant portion of forecasted load growth. Large load forecasts are extremely uncertain, and if large loads do not materialize in the volumes predicted in the forecast used to set the RCPPP requirements, LSEs may be left with stranded investments in resources they cannot sell, because neither they nor other LSEs have a need for those resources. The result will be unnecessary costs for customers.

E. Option 3's Misalignment with Other Compliance Programs Risks Unnecessary Procurement and Higher Costs Without Corresponding Benefits

Option 3 does not align with the ultimate reliability and clean energy compliance requirements that long-term planning and procurement are intended to satisfy. Option 3 uses an Effective Load Carrying Capability (ELCC)-based counting framework, resulting in a single value per month by technology that can swing dramatically based upon the portfolio of resources

on the system. This is in contrast to the ultimate compliance measurement for the RA SOD program, which uses 24 values, one for each hour of the worst day of the month. Option 3 also misaligns with the RPS program, the ultimate compliance measurement for clean energy objectives. Option 3 requires new resource procurement based upon the GHG-reduction targets achieved through the PSP. This fails to consider whether the LSEs served their customers' load with sufficient amounts of clean energy, which is the basis for the RPS program.

Inconsistent planning standards will likely lead to higher costs for customers \because LSEs will always need to procure to the higher of the two standards to be in full compliance, without corresponding reliability or clean energy benefits. From a reliability perspective, adding an additional reliability constraint will never result in a lower total requirement (or cost). Procurement will either bind on marginal ELCC (mELCC) or SOD. In addition, due to the lack of alignment between the two compliance requirements, LSEs cannot optimize for both at once. Any time LSE SOD requirements and mELCC requirements are inconsistent, an LSE's portfolio could comply with one program but not the other. When this occurs, the LSE would either need to procure additional resources or face penalties for non-compliance. Either outcome results in unnecessary costs to customers due to a misalignment in mid- to long-term requirements in RCPPP and short-term requirements in the RA program.

The Commission has established SOD as the reliability metric for the system and the RPS program as the clean energy metric for the system. Adding different standards for the same need will simply increase costs while adding complexity for both LSEs and Commission staff. The RCPPP should therefore be designed so that mid- to long-term procurement sets the system up to meet the reliability and clean energy needs established in the RA program and RPS program, respectively.

F. Option 3 Will Not Facilitate the Planning Necessary for the Orderly Retention and/or Retirement of Existing Resources

A long-term procurement program that limits requirements to new resources fails to ensure orderly retirement of existing resources. It would also complicate the eligibility of repowers. The treatment of repowers is an issue that has yet to be addressed under the existing procurement order structure, and Option 3 will likely face the same challenge. Option 1, which details a New + Existing Resource Requirement that meets total capacity needs, on the other hand, greatly simplifies the treatment of repowers and incents the retention of existing resources necessary for reliability or clean energy objectives.

G. Option 3 Challenges LLT Planning and Procurement

Option 3 will create significant challenges for LLT resource planning and procurement. Five years between need allocation and commercial operations is not enough time for procurement of LLT resources. Technology- or attribute-specific orders coupled with five-year compliance periods therefore raise several challenges.

First, if the Commission orders procurement of LLT resources, it will likely not be feasible for LSEs to procure and bring an LLT resource to commercial operation within five years. *Second*, LSEs do not have assurances that LLT resources procured further than five years out will count due to the resource- or attribute-specific nature of Option 3. *Third*, the aggregated PSP will be allocated to all LSEs regardless of what is in their individual plan, potentially leading to a LLT resource already in development for one LSE creating a procurement obligation for all LSEs.²⁵ *Fourth*, by tying a resource's procurement value primarily to its alignment with

²⁵ For example, assume an LSE begins developing a LLT resource in the six to ten year range and it has made enough progress that the resource is included in the individual LSE's IRP and the overall PSP. The Option 3 process would allocate the overall PSP to all LSEs on a load ratio share. This process will mean that the LSE that included an LLT resources will get *part* of that resource back as a requirement and

the PSP, Option 3 could create incentives for LSEs to favor resources that are easiest to build to meet compliance timelines rather than pursue other sources of portfolio value, such as resource diversification and technological advancement. Today, LSEs use their IRPs, in part, to explore emerging technologies for potential procurement opportunities and to signal commercial interest. LSE IRPs are a point in time outlook at a long planning horizon and are proposing one possible scenario (out of many) to meet goals. Inclusion of resources in an LSE's individual IRP is an indication, and LSE procurement ultimately depends on portfolio fit at the time of procurement.

Inclusion of resources in individual IRPs or the PSP does not guarantee that the resource will ultimately be available or affordable in the market for LSEs to procure. Option 3 binds LSEs to their IRPs in a way that dissuades procurement outside of the Commission's prescriptive requirements that otherwise could still meet the Commission's reliability and clean energy objectives in a more affordable manner. Therefore, Option 3 may dissuade LSEs from including in their plans such emerging or difficult-to-develop resources, challenging resource diversity and creating downstream impacts on transmission planning.

III. RESOLVE MODELING AND ANALYSIS OF THE INTERCONNECTION QUEUE DEMONSTRATE THE SHORTCOMINGS OF OPTION 3

To demonstrate the inefficiencies Option 3 will likely create, CalCCA has explored several RESOLVE runs based on different price sensitivities for solar, storage, geothermal, and wind. CalCCA then compared these sensitivities to a "Least-Cost Portfolio" (baseline) developed using RESOLVE workbooks for LSEs' 2026 IRPs to find the least-cost 2032 portfolio under

all other LSEs will also get their load ratio share of the resource as a requirement. By doing this, the one LSE will be long on their LLT requirement and all other LSEs will be short since they have not begun planning for an LLT resource.

these assumptions.²⁶ CalCCA has also compared the Least-Cost Portfolio to the portfolio of resources in the interconnection queue with 2032 online dates to determine whether procurement requirements driven by RESOLVE portfolios would have been feasible given the resources available for LSEs to procure.

In summary and as set forth below, CalCCA's analysis finds that: (1) several RESOLVE-optimized portfolios can meet reliability and clean energy targets, and the least-cost portfolio that achieves these targets varies significantly based upon price uncertainty; and (2) resource- or attribute-specific procurement orders will likely be costly and/or infeasible, given there are insufficient volumes of geothermal and LDES resources in the CAISO queue to support the amount of capacity from these resources in the Least-Cost Portfolio.

A. The Least-Cost Portfolio Achieving Reliability and Clean Energy Targets Varies Significantly Based on Price Uncertainty

CalCCA's analysis using the RESOLVE model demonstrates that creating resource- or attribute- specific RCPPP requirements based on the PSP may prevent the market from achieving reliability and clean energy goals cost effectively. CalCCA conducted 10 RESOLVE model runs using different resource cost assumptions, including lower costs for solar, storage, geothermal, and wind resources, and higher costs for solar, storage, and wind. The RESOLVE optimized portfolios met the reliability and clean energy requirements using a different set of resources in each of the 10 different runs, as demonstrated by Figure 1, below.

²⁶ See CPUC RESOLVE Workbooks and Public Case Results Viewers: <https://files.cpuc.ca.gov/energy/modeling/LTPP/RESOLVE%20Workbooks%20and%20Public%20Case%20Results%20Viewers.zip>.

Figure 1
2032 RESOLVE-Selected Build Comparison Under Different Resource Price Sensitivities

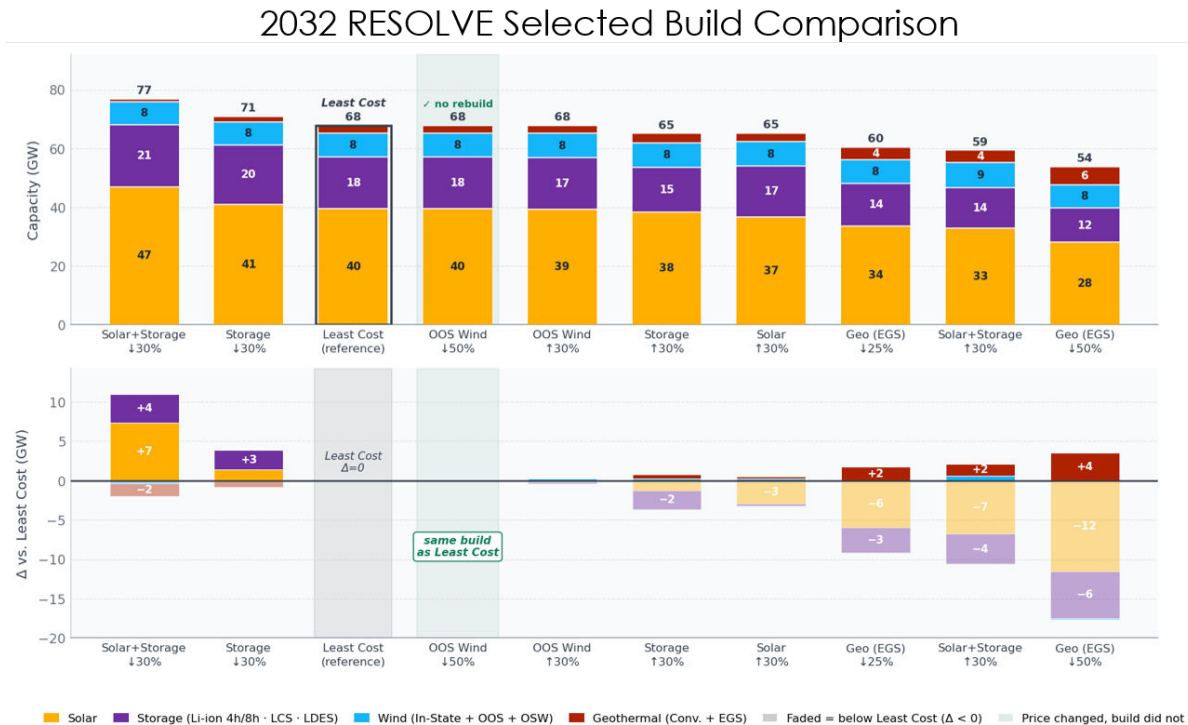


Figure 1 demonstrates that realistic changes in resource price assumptions can have a significant impact on the portfolio of resources RESOLVE selects as the least cost method to meet reliability and clean energy targets. In all portfolios, RESOLVE selects sufficient resources to meet the CAISO GHG target of 22.69 million metric tons of CO₂ (MMT CO₂) in 2032. Importantly, the resources added to meet the GHG target in each portfolio are also more than sufficient to meet the PRM target of 15 percent,²⁷ the RPS target of 60 percent, and the CES target of 77 percent.

²⁷ The Commission established a target reserve margin of roughly 15 percent percent in ELCC for the 2026 IRP updates. See *2024-2026 Integrated Resource Planning (IRP) Inputs & Assumptions* (Feb. 2026), at 179-180, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy->

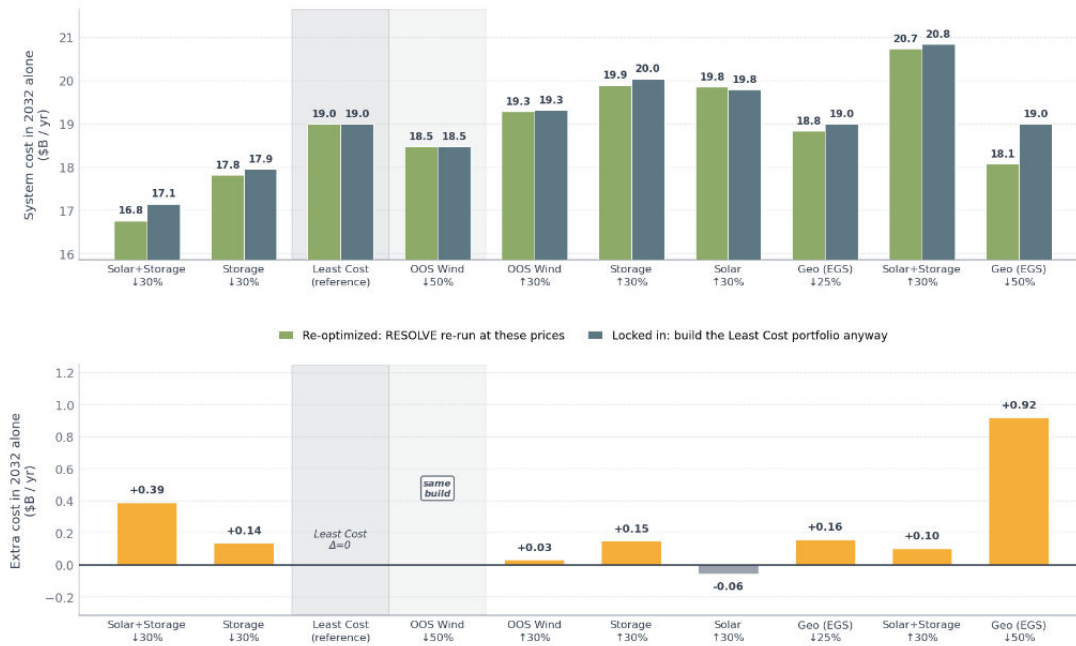
Figure 2
Achieved PRM, RPS, and CES Under Each RESOLVE-Selected Portfolio

Portfolio Heatmap — All 10 RESOLVE Runs at 2032								
	Solar	Storage	Wind	Geo (Conv+EGS)	Total (GW)	Achieved PRM Target 15%	Achieved RPS Target 60%	Achieved CES Target 77%
Solar+Storage ↓30%	46.9	21.2	7.7	0.8	76.6	20.6%	94.7%	103.1%
Storage ↓30%	40.9	20.1	8.0	1.7	70.7	20.7%	93.9%	102.3%
Least Cost · reference	39.6	17.6	8.1	2.4	67.7	21.5%	93.5%	102.0%
OOS Wind ↓50%	39.5	17.6	8.1	2.4	67.6	21.7%	93.7%	102.1%
OOS Wind ↑30%	39.4	17.4	8.3	2.5	67.6	21.2%	93.7%	102.1%
Storage ↑30%	38.3	15.2	8.4	3.0	64.9	20.2%	93.6%	102.1%
Solar ↑30%	36.7	17.2	8.4	2.7	65.0	21.0%	93.3%	101.7%
Geo (EGS) ↓25%	33.6	14.4	8.1	4.2	60.2	20.3%	93.1%	101.6%
Solar+Storage ↑30%	32.8	13.7	8.7	4.0	59.2	19.6%	92.8%	101.2%
Geo (EGS) ↓50%	28.0	11.6	7.9	6.0	53.6	20.8%	92.4%	100.9%

Locking into the Least-Cost Portfolio rather than allowing LSEs to reoptimize their portfolios to align with market conditions results in unnecessary additional costs and prevents LSEs from alternative portfolio mixes that achieve the goals at a cost lower than the modeled least cost portfolio. Figure 3 below shows the costs ratepayers will incur if LSE procurement is locked into the Least-Cost Portfolio (blue) versus if LSE procurement can be reoptimized under updated price assumptions (green). Even modest changes in price assumptions can result in millions of dollars in unnecessary costs if procurement is locked into the PSP portfolios.

[division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf](#).

Figure 3
Reoptimized Portfolio vs Locked-in Least Cost Portfolio Cost Comparison²⁸



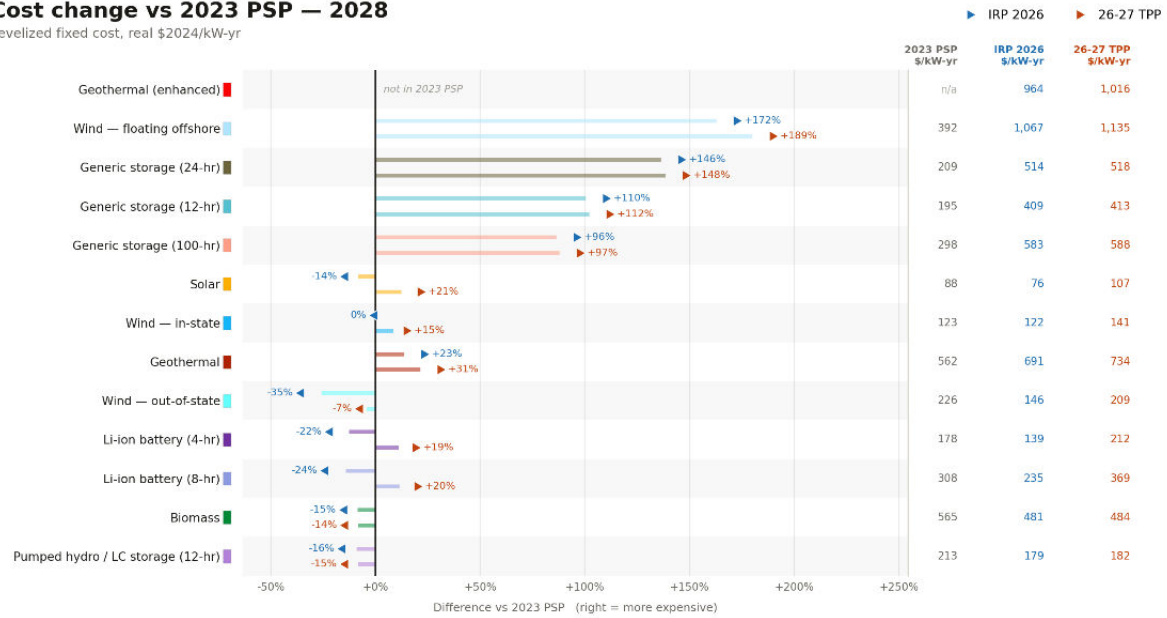
The magnitude of price changes in CalCCA’s price sensitivities is not exaggerated. Indeed, recent history shows that cost inputs into RESOLVE have changed significantly in three years. Figure 4 below demonstrates the magnitude of cost changes between the 2023 PSP, the 2026 IRP assumptions from the RESOLVE Workbooks, and the 2026-2027 TPP Portfolio.

²⁸ The negative costs in the scenario where solar costs increase by 30% is likely due to approximations in our approach that apply a technology-wide median resource unit cost, opposed to a site-specific cost, when estimating the potential excess costs.

Figure 4
Resource Cost Assumption Variability from 2023-2026

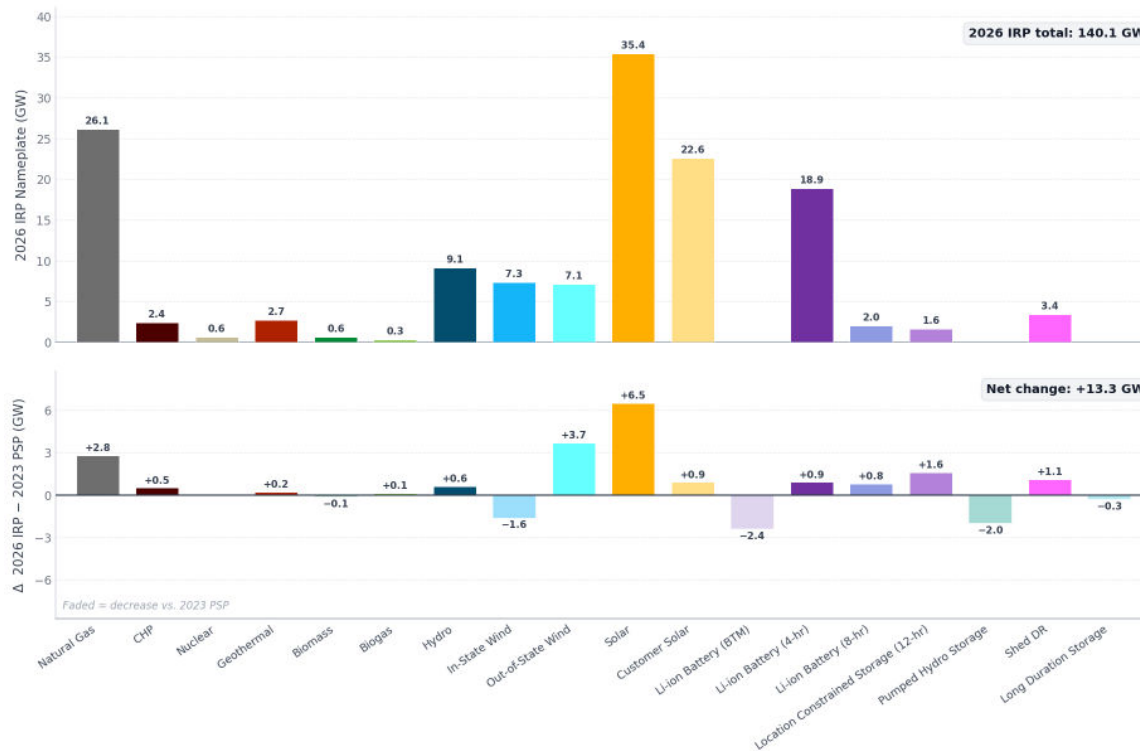
Cost change vs 2023 PSP — 2028

Levelized fixed cost, real \$2024/kW-yr



The price changes have significant impacts on the portfolio of resources chosen by RESOLVE. Figure 5 below demonstrates how the 2026 Least-Cost Portfolio differs from the 2023 PSP.

Figure 5
Difference in Capacity Amounts Between 2023 PSP and 2026 RESOLVE-Selected Portfolio



Binding LSE procurement requirements to 2023 PSP would have potentially prevented high-value procurement. For example, the Least-Cost Portfolio includes 3.7 GW more out-of-state (OOS) wind than the 2023 PSP. Had LSEs been prescribed certain amounts of different technologies to procure, LSEs may not have been able to bring the Sunzia wind project to commercial operations due to the added risk of non-compliance for procurement outside of the prescriptive orders.

For these reasons, constraining LSE procurement to the PSP, as Option 3 proposes, will likely not result in cost-effective outcomes because it limits LSEs' ability to adjust to changes in price and market conditions. The Commission should therefore reject Option 3, as it does not achieve the Commission's stated RCPPP goal of supporting least-cost procurement. In addition

to directly harming ratepayers through unnecessary and avoidable costs, a long-term procurement program that does not prioritize affordability and that increases rates will risk hindering California’s decarbonization and electrification goals. As California plans and prepares for the energy transition, in which RCPPP will play a fundamental role, it is critical that the Commission adopts a framework that enables LSEs to make cost-effective procurement decisions in order to meet the state’s goals at least-cost.

B. A Technology’s Inclusion in the PSP Does Not Guarantee Its Availability in the Market

CalCCA compared the Least-Cost Portfolio to the portfolio of resources in the interconnection queue with online dates of 2032 or earlier to determine whether procurement requirements driven by the RESOLVE-selected portfolio would have been feasible given the resources available for LSEs to procure. Table 1 demonstrates that there are significant discrepancies between the amount of geothermal and LDES in the portfolios versus the interconnection queue. These resources are those that the Commission has specifically ordered in its most recent procurement order. The margin of wind capacity in the queue relative to the portfolios is also very small and would likely cause procurement and cost challenges should resource-specific procurement be ordered.

Table 1
Ability for 2032 CAISO Interconnection Queue Projects to Achieve the Least Cost Portfolio

Technology	CAISO Interconnection Phase II MW	Least Cost Portfolio Planned MW	% of Need at Phase II	Long-term System Need	Remaining Need MW
In State Geothermal	62	776	8.0	YES	714
Biomass	0	0		n/a	0
Wind	2707	2500	108.3	YES	0
Offshore Wind	1029	0		n/a	0
Solar	57842	39600	146.1	NO	0
Battery	79049	15600	506.7	NO	0
LDES	1142	2000	57.1	YES	858

CalCCA also compared OOS resources in the portfolio to the west-wide queue.²⁹ This comparison similarly shows a long-term system need for additional capacity that may not be filled by the existing queue. As shown in Table 2, the amount of OOS geothermal and wind in the Western Electric Coordinating Council (WECC) wide queue exceeds the amount in the Least-Cost Portfolio. However, this must be evaluated in the context of other factors impacting California’s ability to obtain OOS resources for RCPPP requirements. The CAISO serves roughly 24 percent of the total electricity demand in WECC, and the amounts of OOS geothermal and wind in the Least-Cost Portfolio well exceed this proportion. The amount of OOS geothermal in the portfolio is 43 percent of the WECC-wide queue and the amount of OOS wind in the portfolio is 36 percent of the WECC-wide queue. Further exacerbating this issue, historically, only 10 percent of the projects in the West (non-ISO) queues made it to completion.³⁰ This, along with forecasted capacity constraints in parts of the West,³¹ the uncertain availability of long-term maximum import capability (MIC), and additional barriers to developing interregional transmission to the CAISO border, means it is not reasonable to assume such significant portions of the WECC-wide queue can be dedicated to serve California load in a timely and affordable manner.

²⁹ West-wide queue data is available from the Lawrence Berkeley National Laboratory (LBNL), <https://emp.lbl.gov/publications/queued-2026-edition-characteristics>.

³⁰ LBNL, “Queued Up: 2026 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2025” (June 2026), <https://emp.lbl.gov/sites/default/files/2026-06/Queued%20Up%202026%20Edition.pdf>.

³¹ Western Electric Coordinating Council, *2025 Western Assessment of Resource Adequacy*, “[t]he West’s planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see energy shortfalls as early as 2028.”

Table 2
Ability for West-Wide OOS Resource Queue Capacity to Achieve Least Cost Portfolio

Technology	West Regional Queue (excluding CAISO) MW	Least Cost Portfolio Planned MW	% of Need	Long-term System Need
Out of State Geothermal	3876	1668	232.4	YES
OOS Wind	15300	5500	278.2	YES

IV. THE COMMISSION SHOULD ADOPT OPTION 1 + CES BECAUSE A NEW PLUS EXISTING RESOURCE PROCUREMENT FRAMEWORK WILL SUPPORT AN EFFICIENT AND AFFORDABLE PROCUREMENT ENVIRONMENT FOR RELIABILITY AND CLEAN ENERGY NEEDS

CalCCA continues to advocate for an RCPPP that leverages the existing SOD RA program and RPS program for the purpose of mid- to long-term resource development.³² This approach is based on Energy Division Staff’s Reliability Option 1 and CES (Option 1 + CES) which would: (1) identify the total reliability need and include procurement requirements for both new *and* existing resources through multi-year RA; and (2) require specific amounts of retail electric sales that must be served by non-emitting resources.³³ Such a framework will result in a durable RCPPP that provides LSEs and developers certainty about mid- to long-term procurement obligations and supports the ability to meet reliability and clean energy objectives in an affordable manner given the practical realities of today’s procurement environment.

³² *California Community Choice Association’s Comments on Administrative Law Judge’s Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025). Key elements of CalCCA’s proposed Option 1 would include: (1) five-year forward showing requirements in alignment with the month-ahead and year-ahead RA processes, with a focus on critical months and hours and reduced percentage requirements in the out years to mitigate against potentially costly over-build resulting from load forecast changes; (2) a penalty waiver process as part of the reliability framework, building upon the “good faith efforts” standard adopted in the MTR decision; (3) a program that is sufficiently transactable so that reliability requirements can be met without excessive costs or over-procurement; and (4) a CES GHG-emissions reduction framework based on actual energy sales as an extension of the RPS program, with incentives to drive new clean resource-build in an affordable manner.

³³ *Attachment A: Staff Proposal: Reliable and Clean Power Procurement Program*, R.20-05-003 (Apr. 29, 2025), at 3: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K140/565140169.PDF>.

In summary, Option 1 + CES is superior to Option 3 because it:

- Provides necessary procurement flexibility to support reliability and clean energy objectives in an affordable manner;
- Ensures proper planning for new and existing resource needs;
- Accounts for an LSE's prior procurement and individual portfolio needs;
- Enables greater efficiency and consolidation of compliance requirements across various programs; and
- Manages load forecast uncertainty.

A. Option 1 + CES Provides Flexibility Necessary to Meet Reliability and Clean Energy Objectives in an Affordable Manner

Option 1 + CES allows LSEs to procure the most economically efficient portfolio of resources that meet reliability and clean energy needs. Under RCPPP, LSEs must manage multiple objectives (*i.e.*, reliability, energy, and environmental). As demonstrated in Section III, above, it will be extremely difficult to identify a clear, single most efficient outcome that balances all these objectives five years forward, let alone establish specific compliance requirements based on this outcome. Additionally, in the current market with supply constraints and lengthy timelines for interconnection, flexibility for LSEs to adjust portfolios before locking them in for compliance will aid in getting more resources under contract and online in an affordable manner.

Option 1 + CES allows LSEs to exercise discretion in determining how best to meet reliability and clean energy objectives while accounting for their customers' needs and preferences. In contrast, Option 3 will impose prescriptive new-resource procurement requirements that remove procurement optionality and constrain LSEs' ability to pivot procurement strategies as new information about needs and/or costs become known. It is therefore clear that Option 1 + CES is more aligned with the Commission's stated goal for RCPPP: "to create and administer a long-term procurement framework... that, in combination

with the [RA] and [RPS] programs, could improve the process for [LSEs] to procure their share of the resources needed to meet electric system reliability and [GHG] emission reduction goals **at least-cost.**”³⁴

B. Option 1 + CES Ensures Proper Planning for New and Existing Resource Needs

By allowing LSEs to leverage existing resources (including those that can be economically repowered), Option 1 + CES allows LSEs to optimize their entire portfolios with new and existing resources in the most cost-effective manner without requiring LSEs to lock in a significant portion of the procurement in expensive long-term contracts. While Option 1 itself does not have specific new build requirements, Option 1 using SOD, coupled with a CES framework with similar long-term contracting requirements as the RPS program, would sufficiently incentivize new build by all LSEs when necessary.

If new resources in LSE portfolios face project delays, LSEs will still be able to meet their reliability needs under Option 1 by contracting with existing resources until their new resources can come online. Under Option 3, such flexibility is not available for the new resource requirement. This means that even if an LSE faces project delays outside of its control and has sufficient existing resources to meet its reliability need, that LSE will still face penalties.

In addition, Option 1 provides a clear path forward for accounting for the reliability and clean energy benefits of repowering and re-contracting with existing renewable and clean energy resources. These resources can provide cost-effective and timely solutions to reliability and clean energy needs identified through RCPMP and should be accounted for when procured by LSEs.

³⁴ See CPUC website regarding RCPMP (emphasis added), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/the-reliable-and-clean-power-procurement-program>.

Option 1 thus better satisfies the Commission’s RCPPP program design principle of “effectively support[ing] the maintenance of existing resources and additions of new clean resources.”³⁵

C. Option 1 + CES Accounts for Load Forecast Uncertainty and Individual LSEs’ Portfolio Needs in a Manner that Ensures Fair and Accurate Need Allocations

RCPPP must be developed in the context of unprecedented load forecast uncertainty. Between 2020 and 2024, retail sales decreased by three percent. In contrast, the CEC 2024 Integrated Energy Policy Report (IEPR) projects retail sales will increase by 25 percent between 2025 and 2030, largely due to increased electrification, electric vehicles (EV), and new data centers.³⁶ The impacts of electrification, EVs, and data centers on load forecasts, however, are highly uncertain and could result in significant changes in LSE requirements as the relevant planning horizon approaches and load forecasts becomes more certain.

Because Option 3 will identify the total new resource need and allocate it to LSEs pro-rata based upon their load ratio share at the time of allocation, need allocations may not accurately reflect an LSE’s share of the need as needs evolve due to changes in load growth assumptions. For example, allocating new resource procurement needs based on current load ratio share could unfairly allocate requirements to LSEs who are not expected to experience load growth. As stated in Section II., above, allowing LSEs to transact resources as the only

³⁵ *Integrated Resource Planning Workshop: Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (May 16, 2025) at 15, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/rcppp/rcppp-workshop-slides-redlined.pdf>.

³⁶ Increase in retail sales is based on the CEC Docket No. 24-IEPR-03, *California Energy Demand 2024-2040 Forecast – Planning Forecast*, 2024 IEPR Demand Forecast for the planning scenario (see Form 1.1c), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=262820>. Drivers of the increase in retail sales are described in CEC Docket No. 24-IEPR-01, *CEC Draft Commission Report, Draft 2024 Integrated Energy Policy Report Update* (Nov. 2024), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=260322&DocumentContentId=96547>.

mechanism to accommodate for such changes is an insufficient solution to a potentially significant problem that may result in customers paying for stranded investments.

Option 1 + CES provides a more efficient and equitable means of addressing this uncertainty because it avoids carving out new resource needs and looks holistically at total portfolio needs.. It allows LSEs to effectively manage load forecast uncertainty by requiring binding showings of new and existing resources at increasing percentages as needs get closer. Need allocation under a multi-year RA framework can be developed to clearly, simply, and fairly reflect LSE needs under uncertainty (*e.g.*, data center load impacts by LSE,³⁷ load migration, load decline, and other factors). Option 1 enables LSEs to set their own hedging strategies for mid- to long-term procurement and to manage their portfolios in light of market conditions and evolving load forecasts. RCPMP requirements should not exceed RA requirements, thereby preserving LSE flexibility to respond to market conditions, manage uncertainty, and optimize procurement.

D. Option 1 + CES Enables Greater Efficiency and Consolidation of Compliance Requirements Across Various Programs

Unlike Option 3, Option 1 + CES closely aligns with the RA and RPS procurement programs, avoiding the need to procure to different standards for the same needs. As stated in Section II., above, the RCPMP should be designed so that mid- to long-term procurement sets the system up to meet the reliability and clean energy needs established in the RA program and RPS program, respectively.

³⁷ CalCCA's proposal in R.25-10-003 would minimize the risk that uncertainty associated with data center load results in inaccurate or unfair allocations under Option 1 + CES. *See California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K418/596418487.PDF>.

From a reliability perspective, the Commission has established SOD as the ultimate reliability metric.³⁸ Mid- to long-term planning and procurement should set the system up for compliance with this metric. In addition, the SOD program will be more stable than a mELCC-based program because the exceedance values used for SOD resource counting are based on historical data averaged over several years. While this historical average will vary over time, this variability will be limited as the oldest year's data rolls off and is replaced by the latest data. In addition, the changes will be based only on the performance of the resource being evaluated and not based upon changes in its value due to changes in the entire portfolio of resources available to meet grid needs. The SOD profiles can also be developed relatively simply and without the reliance on more complex modeling software, allowing more stakeholders to validate the exceedance values. For these reasons, aligning RCPMP with the RA program will provide more certainty to LSEs and enable more cost-effective procurement.

From a clean energy perspective, the RPS program ensures LSEs increase the state's renewable energy production over time. The RPS program has been successful at driving new renewable resource development. Leveraging the success of RPS for the CES will ensure RCPMP is also successful at continuing to advance clean energy targets and provide opportunities to consolidate the RPS and CES reporting requirements. The CES model better aligns with the policy established in SB 100 that "...eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and

³⁸ See D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, R.19-11-009 (July 15, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF>; and D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF>.

100 percent of electricity procured to serve all state agencies by December 31, 2045.”³⁹ The Commission should therefore design a CES framework in a manner that adequately incentivizes investment in new clean build, like the RPS program has done, and supports an affordable system by aligning short-term and mid- to long-term clean energy procurement.

V. TO THE EXTENT THE COMMISSION MOVES FORWARD WITH A NEW RESOURCE PROCUREMENT REQUIREMENT FRAMEWORK (WHICH CALCCA DOES NOT SUPPORT), ONLY OPTION 2 SHOULD BE CONSIDERED, BUT WITH SIGNIFICANT MODIFICATIONS TO ENSURE FEASIBLE, AFFORDABLE, AND EQUITABLE REQUIREMENTS

If the Commission rejects Option 1 in favor of a new resource procurement framework (which CalCCA does not support), it should only adopt Option 2, not Option 3. Option 2 would establish new resource procurement requirements in mELCC terms and allocate them to LSEs based on load-ratio share. While Option 2 is preferable to Option 3 because it does not require prescriptive procurement of the PSP, Option 2 still requires significant modifications to ensure procurement requirements are feasible, affordable, and equitable. The following sections describe recommended modifications regarding need determination, need allocation, compliance, and enforcement. These modifications should be applied to any RCPPP framework the Commission adopts, though the necessary method of implementation may vary depending on the ultimate framework adopted. For clarity and simplicity, CalCCA discusses these modifications in the context of Option 2, as the better alternative of the two new resource frameworks the Commission is considering.

A. Option 2 Should be Modified Regarding Need Determinations

1. The RCPPP Need Determination Should Establish Technology-Neutral Procurement Requirements

³⁹ SB 100 (amending Pub. Util. Code §454.53.(a)).

Energy Division states that the Option 2 need determination will “specify the needed quantities of resource attributes, such as effective capacity, firm energy, and/or clean energy attributes, over a specified period.”⁴⁰ The Commission, however, should not order procurement of specific attributes, other than the qualifying capacity (QC) value. As described above, past attribute-specific procurement orders have demonstrated that, even if the attributes are intended to be technology neutral, they often apply only to one or few technology types that are not abundantly available in the market. Overly prescriptive procurement requirements that can be met by a limited pool of resources will provide leverage to suppliers to negotiate high prices and unfavorable contract terms at the ultimate expense of customers.

For the reasons described above, the Commission should adopt SOD accounting for RCPPP. As such, LSEs should be required to show sufficient SOD capacity in critical months and hours when the need is further out, building to a full SOD year-ahead and month-ahead RA showings, as proposed in CalCCA’s Option 1 proposal.⁴¹ If the Commission adopts a new resource procurement requirement with mELCC accounting, it should do so only on a temporary basis, until it can transition to a single need determination and accounting methodology for the RCPPP and RA programs.

2. RCPPP Requirements Should Not Include Commission-Mandated “Buffers”

The buffer included in Option 2 should be rejected.⁴² The Commission states that a buffer is intended to “... account for multiple types of uncertainty, including uncertainty in the load

⁴⁰ *Attachment A: Staff Proposal: Reliable and Clean Power Procurement Program*, R.20-05-003 (Apr. 29, 2025), at 3: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K140/565140169.PDF>.

⁴¹ *California Community Choice Association’s Comments on Administrative Law Judge’s Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), Table 11, at 16, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF>.

⁴² Option 3 also includes a buffer, which should be rejected in the event Option 3 is adopted.

forecast, uncertainty in LSE compliance, and to allow for a competitive market.”⁴³ However, these uncertainties and market competitiveness are better addressed in alternative ways.

LSEs already account for the risk of project delays in their own procurement strategies to mitigate potential non-compliance and penalties. Imposing a generic Commission-established buffer will unnecessarily duplicate these efforts and is likely to result in costly excess procurement. LSEs are better positioned to manage the project-delay risk because the appropriate mitigation strategy depends on the specific resources in their portfolios. A uniform buffer applied to all LSEs will fail to account for the differences in LSE portfolios and the level of COD delay-risks associated with these portfolios.

Practical contracting realities have created a challenging procurement environment for all LSEs. Adding a buffer will unnecessarily: (1) add demand to the market for which there is no demonstrated need; (2) exacerbate supply constraints; (3) raise prices; (4) increase the probability that entities will pay exorbitant prices or be unable to comply with the total procurement obligation including the buffer; and (5) potentially penalize an entity for failing to meet a buffer that was ultimately unnecessary to meet reliability and clean energy needs at the expense of their customers in the case of departed load customers.

B. Option 2 Need Allocation Methodologies Should be Modified

1. A Separate Process Should be Established for Data Center Load Allocations

The Commission’s processes for allocating procurement obligations should be re-evaluated in the context of data center loads and the novel impacts they have on load forecasting

⁴³ Ruling, at 9.

and resource planning. The CEC,⁴⁴ other state and federal regulators,⁴⁵ researchers,⁴⁶ and the media have widely noted the difficulty of concluding whether data center loads will materialize. Given the unique characteristics and uncertainty associated with data center load, the Commission should establish new processes for incorporating data center load into RCPPP obligations. These processes should include the following components: (1) coordination with the RA proceeding to adopt milestone-based RA allocation process for data center loads;⁴⁷ (2) exclusion of data center loads from RCPPP requirements until they are allocated for RA requirements pursuant to (1); and (3) inclusion of data center loads into RCPPP new resource obligations only after data center is added to an LSE's RA requirement.

In the RA proceeding (R.25-10-003), CalCCA recently proposed a milestone-based RA allocation proposal for data center loads.⁴⁸ Under CalCCA's proposal, RA obligations associated with data center loads will be allocated to the LSE serving the data center customer once certain

⁴⁴ CEC Docket No. 24-IEPR-03, Jenny Chen, "Data Center Forecast", (Dec. 23, 2024) (Chen Forecast), at 2, https://www.energy.ca.gov/sites/default/files/202412/Data_Center_Forecast_Update_ada.pdf, (acknowledging the uncertainties involved with data center certainty analysis, and stating during the 2024 Demand Forecast development that "[t]his has been a continually evolving process, as we learn more every day. The data center methodology will be improved next year.").

⁴⁵ For example, a recent letter from Federal Energy Regulatory Commission (FERC) Chairman Rosner to regional transmission organizations and independent system operators including the CAISO highlights these challenges and opens a dialogue regarding large load interconnections. *See* FERC Chairman Rosner's Letter to the RTOs/ISOs on Large Load Forecasting (Sept. 18, 2025), <https://www.ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting> ("Our experience to date tells us that large loads, such as data centers, have characteristics that call for new and improved forecasting methods. Given the size and volume of new large load interconnection requests, I'm optimistic that utilities have an opportunity to apply similar criteria to those currently used to assess the commercial readiness of large projects in the generator interconnection queue. These objective criteria include observable milestones such as contracts, financial security deposits, and physical site control.").

⁴⁶ *See, e.g.*, Fast, Flexible Solutions for Data Centers, Rocky Mountain Institute (July 17, 2025), <https://rmi.org/fast-flexible-solutions-for-data-centers/> ("Some estimate that speculative interconnection requests could be five to ten times more than the actual number of data centers, as data centers "shop around" for the fastest interconnection opportunities and cancel data center projects in oversupply.").

⁴⁷ *California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K418/596418487.PDF>.

⁴⁸ *Ibid.*

milestones have been met that provide confidence that the data center load will come online. These milestones include the data center customer has: (1) chosen a generation provider; (2) obtained an executed interconnection agreement and site control; (3) obtained an energization date within the RA year; and (4) other interconnection information. The Commission deferred adoption of the proposal due to open implementation questions and the need for further development.⁴⁹

The Commission should move ahead with further development of this proposal for the purposes of RCPPP, to ensure procurement obligations are accurately and fairly allocated in a manner that realistically reflects the amount of data center load that will need to be served. To do so, the Commission should work with the CEC to identify the portion of the IEPR “Planning Scenario” load forecast that is attributable to data centers. Next, the data center load portion of the load forecast can be excluded from the RCPPP need determination until the data center load has met the milestones established in the RA allocation process. Once they meet these milestones, and are then included in the RA obligations for the LSEs serving the load, the Commission can include the data center load into the RCPPP obligation for the LSE serving the load for the next 5 year forward compliance period. Until the compliance date, the LSE would need to meet its RA obligations for the data center load with new and existing resources. As described above, LSEs should be able to meet RCPPP requirements through new procurement or excess from prior compliance periods.

2. New Resource Need Should be Allocated Based on Each LSE’s Forecasted Load Ratio Share of the Incremental Need

The Commission should ensure that the RCPPP need allocation methodology fairly and accurately reflects each LSEs’ contribution to the identified need. Accordingly, if the

⁴⁹ *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, R.25-10-003 (July 10, 2026) at 146, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M610/K575/610575803.PDF>.

Commission adopts a new resource-only procurement framework, it should modify Option 2 to allocate the new resource need based on each LSE's load ratio share of the incremental need calculated using forecasted load for the compliance year (*i.e.*, the year in which the resource must achieve COD).

Past procurement orders have been based upon an LSEs' load ratio share at the time of need allocation. For example, D.26-02-057 allocated requirements based upon the load ratio share used for the 2026 RA allocations, rather than forecasted load ratio share during the compliance period (2029-2032).⁵⁰ For longer term procurement obligations such as RCPPP, the Commission should use forecasted load ratio share during the compliance period, so that if an LSEs' share of load changes between the need allocation and the compliance year, due to factors such as expansions, shifts in regional power consumption, or other factors, LSEs' allocations fairly reflect their contribution to the need.

Because load forecasts are inherently more uncertain in the years further out, this proposal should be adopted in tandem with the data center allocation proposal in Section V.B.1 above. Data centers are one of the more significant sources of load forecast uncertainty. This proposal will effectively manage this uncertainty for the purposes of informing procurement requirements, which is needed should allocations be based on forecasted load ratio share during the compliance year rather than the year of need allocation.

3. Indicative Needs Should be Allocated to LSEs Beyond Five Years

The Commission should allocate non-binding, indicative allocations to LSEs for years five through ten to help LSEs better plan for future needs. LLT resources require longer than five

⁵⁰ D.26-02-057, O¶ 6.

years to contract and develop. Indicative need allocations will provide LSEs with more information that they can use to help plan LLT procurement before binding needs are allocated.

4. Need Allocations Should be Provided to LSEs Confidentially

The Commission should take measures to ensure that LSE allocations under a new procurement framework do not reveal an LSE's net procurement position to potential sellers. While the Commission has previously publicly disclosed LSE-specific allocations in prior procurement orders, under the RCPMP, LSE-specific allocations should be communicated confidentially. Protecting this information will limit sellers' ability to identify an individual LSE's procurement needs.

For the same reasons, the Commission should keep confidential individual LSE compliance with RCPMP obligations. Failure to protect the confidentiality of LSEs' net positions could potentially create opportunities for market sellers to exercise market power and ultimately exacerbate the affordability crisis. The Commission should therefore publicly report only aggregate information on compliance with prior MTR orders, avoiding disclosure of the net position of any individual entity.

C. Option 2 Compliance and Enforcement Components Should be Modified

1. LSE Excess Procurement Should be Eligible for RCPMP Obligations

Under Option 2, the Commission should continue to allow past procurement in excess of the baseline plus prior orders to count towards an LSE's RCPMP obligation. This practice was adopted in D.26-02-057,⁵¹ proposed in the Ruling, and should continue under a new resource procurement framework to ensure LSEs are not disincentivized to procure outside of RCPMP

⁵¹ D.26-02-057, at 47.

procurement obligations. Otherwise, LSEs may avoid taking early actions, which would have particularly negative impacts on LLT resources that take longer than five years to develop.

2. RCPPP Reporting and Compliance Obligations Should Realistically Reflect the Timing of Procurement Processes

The Commission should allow sufficient time between need allocation and contracting to realistically reflect the timing of the procurement process. Under Option 2, the Commission proposes the following requirements: 100 percent online in Y+0; 90 percent contracted in Y+1; 80 percent contracted in Y+2; 70 percent contracted in Y+3; and 60 percent contracted in Y+4. If needs are allocated in Y+5, contracting requirements in Y+4 are likely too compressed given the time it takes to conduct LSEs' procurement processes, including issuing RFOs, evaluating bids, and negotiating and executing agreements. Instead, the Commission should allocate needs in Y+5 and require showings of contracts beginning in Y+3, to allow two full years for LSEs to undergo their procurement processes before showing contracts. As described below, contract showings for RCPPP should be informational only, so that LSEs are not penalized multiple times for the same deficiency.

3. Products and Obligations Should be Sufficiently Transactable to Allow Procurement Needs to be Met in an Affordable Manner

RCPPP obligations must be sufficiently transactable to ensure LSEs have a pathway to procure their share of system reliability and GHG reduction goals at least cost. The Ruling states that LSEs under Option 3 would be able to accommodate load changes through "options to trade or sell resources that are no longer needed to serve load or for program compliance."⁵² If the Commission adopts RCPPP obligations that can only be met by new resources, other means of transactability will be necessary. That is, an LSE that is over-procured for its new resource

⁵² Ruling, at 11.

requirement should be able to be compensated by another LSE for its excess capacity. A mechanism to trade obligations is necessary because the long position of one LSE may be comprised of resources that do not fit with the need of the short LSE, even though in aggregate, reliability requirements are met. This can be the case with mELCC in Option 2 and is certainly the case with Option 3, where the obligation is resource-specific. These problems can be exacerbated when the RA portfolios of the two LSEs also differ. In such a case, while a MW of a resource procured for RCPMP may meet the short LSEs needs, it may be incompatible with its RA position and would require the LSE to buy additional resources to meet both objectives. This would be suboptimal to other options, such as allowing for sufficient transactability to meet compliance obligations.

The Commission has taken steps to allow these types of transactions for the MTR Order if both LSEs trade portions of their compliance obligations.⁵³ If RCPMP moves forward with procurement obligations for new resources only, the Commission should allow LSEs to transact portions of their compliance obligations without restricting transactions to those that involve trades of both LSEs' obligations to fully enable LSEs to optimize procurement, maximize market efficiencies, and minimize costs.

⁵³ See 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>, O¶ 10 at 89 (“Any two load serving entities (LSEs) with compliance obligations under Decision (D.) 19-11-016, D.21-06-035, and/or this order may trade compliance obligations in arrangements that may include financial remuneration, but may not result in one LSE being relieved of its entire procurement obligation under D.21-06-035 or this order. Both LSEs must trade portions of their compliance obligations under this provision.”).

4. The RCPMP Compliance Framework Should Include a Good Faith Efforts Assessment and Alternative Compliance Pathway

The Commission should allow LSEs to seek a waiver of penalties when circumstances make procurement exceedingly difficult and potentially unaffordable for customers, using the “good faith efforts” standard adopted in the MTR Order as a starting point.⁵⁴ A meaningful good faith efforts process for RCPMP will balance the need to avoid exorbitant costs with the need to meet reliability targets, particularly in the current challenging procurement environment.

The compliance framework should account for unforeseen or extraordinary circumstances that may affect procurement over a multi-year horizon, as there are many factors outside the control of LSEs— and in some cases, developers—that can impact project viability and timelines. For example, a project may experience a sudden cancellation just prior to a compliance deadline, necessitating an LSE to execute a new contract to replace it. This situation could occur even if the LSE conducted robust procurement outreach, bid review, and vetting of counterparties.

“Good faith efforts” should be defined as documented, timely, and reasonable procurement actions undertaken by an LSE to meet procurement obligations. Criteria used to evaluate good faith efforts should maintain the integrity of the compliance incentive framework and distinguish between LSEs that did not make reasonable procurement efforts and those that did.⁵⁵ The procurement process—from contracting, development, permitting, and

⁵⁴ D.21-06-035, Conclusion of Law (COL) 27.

⁵⁵ Criteria used to evaluate good faith efforts could include a combination of the following: (1) did the LSE conduct timely solicitations (*e.g.*, RFO)?; (2) did the LSE pursue means other than an RFO to bilaterally procure new resources, if permitted by the LSE’s governing board?; (3) did the LSE reasonably pursue offers to negotiate acceptable terms and conditions?; (4) did the LSE have reasonable terms and conditions to bind the seller to completing the project and key milestones on time and within budget?; (5) did the LSE have a reasonable method to ensure sufficient expertise of the developer to complete the project?; (6) did the LSE make reasonable efforts to address potential project failures in addition to terms and conditions binding the seller to completing the project given the expertise of the developer?; (7) did the LSE make reasonable efforts to meet alternative compliance mechanisms available to them?; or (8) did the LSE sign a contract with a project to replace the capacity from an initial project that ultimately

interconnection—is complex with many co-dependent variables impacting a project’s progression. Without a good-faith efforts standard to account for these circumstances, ratepayers can be subject to unnecessary costs either through unnecessary procurement costs to backfill temporary or unavoidable compliance gaps or through penalty costs arising from circumstances outside the LSEs’ control.

The Commission should also extend the alternative compliance pathway adopted in D.25-09-007.⁵⁶ The alternative compliance pathway allows an LSE to be deemed in compliance with all of the procurement requirements of D.21-06-035 and D.23-02-040,⁵⁷ as modified by D.24-02-047,⁵⁸ if the LSE demonstrates the following: (1) the LSE sufficiently executed long term contracts that meet the applicable MTR procurement requirement; and (2) the LSE has met its month-ahead system RA requirement for each month that the procurement is delayed, by the deadline for any RA deficiency. This process will allow LSEs to cost-effectively manage project delays or cancellations while ensuring reliability requirements continue to be met.

failed due to circumstances outside of the LSE’s control? Despite all of the above: (1) did the LSE receive no bids; (2) did the LSE receive bids insufficient to meet its procurement obligation?; (3) did the LSE receive bids indicative of market power defined as 1.2 times Net CONE for the compliance category the resource is being used for (e.g., generic MTR – battery storage Net CONE, long-lead time (LLT) MTR – geothermal Net CONE)?; (4) did the LSE receive bids or negotiated contract terms with unreasonable and/or non-conventional terms and/or conditions (e.g., terms and conditions that unduly burden the buyer, such as a contract with a generating resource with an expected life of 20-25 years with a cost at or near net CONE recovered over 10 years with no option for contract extension, a contract with significant LSE exposure to additional cost liability)?; (5) was the developer unable to complete the project despite being a reliable developer?; (6) were reasonable offers to replace the contract with on time delivery not available?; or (7) did other circumstances prevent the LSE from meeting its obligation?

⁵⁶ D.25-09-007, *Decision Granting, with Modifications, Southern California Edison Company’s Petition for Modification of Decisions 23-02-040 and 24-02-047*, R.20-05-003 (Sept. 18, 2025), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M581/K576/581576925.PDF>.

⁵⁷ D.23-02-040.

⁵⁸ D.24-02-047, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, R.19-11-009 (July 15, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF>.

5. Penalties Should Only be Assessed on COD Deficiencies to Prevent Duplicative Penalties for the Same Deficiency

If the Commission adopts a new resource procurement framework instead of a new plus existing framework, the Commission should assess compliance on whether the LSE brought sufficient resources online to meet its requirements. Option 2 would penalize LSEs for both contracting deficiencies *and* COD deficiencies. Because the ultimate objective of a new resource procurement framework is to bring new resources online, the Commission should not assess penalties on both contracting requirements. Otherwise, LSEs would essentially be penalized twice for the same deficiency under RCPMP, once when the LSE did not have sufficient capacity under contract and again when the LSE does not have sufficient capacity that reaches COD. Further, LSEs already face penalties for contracting insufficiency under the RA program. Instead of layering on multiple penalties for the same deficiency, the Commission should require LSEs to report the status of their contracting efforts so that the Commission is aware of LSEs' progress towards compliance and, if COD deficiencies result without qualifying good faith efforts, use the proposed net cost-of-new-entry (CONE) penalties for those deficiencies. Alternatively, the Commission could establish an administrative penalty for contracting deficiencies and charge LSEs the difference between the administrative penalty and net CONE for the COD deficiency so that the total penalty paid does not exceed net CONE.

VI. SUMMARY OF DIFFERENCES BETWEEN OPTION 3 AND MODIFIED OPTION 2

Table 3 below provides a comparison of Option 3 and a modified Option 2. For the reasons above, the modified Option 2 should be pursued rather than Option 3, only if the Commission foregoes a new + existing procurement framework. As described above, these modifications should apply to any RCPMP framework the Commission adopts, though the necessary method of implementation may vary depending on the ultimate framework adopted.

For clarity and simplicity, CalCCA discusses these modifications in the context of Option 2, as the better alternative of the two frameworks with requirements for only new resources the Commission is considering.

Table 3
Comparison of Option 3 and CalCCA's Proposed Modified Option 2

	Option 3	Modified Option 2
Need Determination	New resource requirement based on the PSP Portfolio: New resource attributes needed in 5-year timeframe = total procurement need determination for 5 years from the adopted portfolio One percent buffer	New resource requirement based on hours of need in SOD terms - mELCC new capacity need <i>only</i> in the interim, if SOD cannot be implemented immediately - No technology or attribute specific requirements No buffer
Need Allocation	Each LSE responsible for procuring its load ratio share of the PSP's new resources LSEs could show compliance with each category in a range with a minimum and maximum level E.g., between 70 and 130 percent for each resource or attribute-based category	Separate process for data center load allocations: - Exclude data center load from RCPPP requirements until allocated for RA requirements - Allow data center load RA obligations to be met with new + existing resources using CalCCA's milestone-based proposal in R.25-10-003⁵⁹ - Once data center is added to an LSE's RA requirement, new resource requirement is added to that LSE's RCPPP requirement for future date - Could be met by excess from prior periods or new procurement Each LSE responsible for procuring its load ratio share of the new resource need; load ratio share determined based on forecasted load of compliance year

⁵⁹ California Community Choice Association's Track 1 Proposals, R.25-10-003 (Jan. 23, 2026), <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=596418487>.

	<i>Option 3</i>	<i>Modified Option 2</i>
		Indicative needs beyond five years allocated to LSEs Needs allocated to each LSE confidentially
Compliance and Enforcement	LSEs must show: • 100 percent contracted 2-3 years following allocation • 100 percent online 5-years following allocation Net CONE penalty for online requirement Lower administrative penalty amount for contract requirement	LSE excess procurement eligible for future compliance obligations Lower contracting percentages in out years: • Y0 – 100 percent online • Y1 – 90 percent contracted • Y2 – 80 percent contracted • Y3 – 70 percent contracted No penalty for contract requirement (informational only) Sufficient transactability of products and obligations “Good faith efforts” process

VII. CALCCA RESPONSES TO SECTION 4 OF THE RULING: QUESTIONS FOR PARTIES

1. Does this ruling describe a workable framework for an RCPMP that will achieve the goals of IRP, pursuant to SB 350? Why or why not?

No, for the reasons described in Section II. and III., above, the Ruling does not describe a workable framework for RCPMP.

2. Will the proposal described in this ruling be simpler to implement than other proposals under consideration? Why or why not? Compare and contrast benefits and costs as directly as possible.

No - while Option 3 may be simpler for the Commission to implement in some respects, as it is similar to the past ad hoc procurement orders and uses the existing PSP portfolio development process, Option 3 severely complicates LSEs’ procurement processes. Option 3 continues to ignore the core tension of inconsistent planning standards across the RCPMP, RA,

and RPS programs, which would lead to higher procurement costs at the expense of ratepayers. It also continues to employ a resource baseline and does not have a clear pathway for LSEs to contract with existing resources with expiring contracts that can continue to contribute to grid reliability and/or clean energy targets. Ordering resource or attribute-specific procurement will further complicate these procurement processes, adding costs and potentially making procurement requirements infeasible. The Commission can prevent these challenges by adopting Option 1, which will simplify procurement requirements and compliance by aligning with existing programs, seamlessly accounting for new and existing resources, and obviating the need for a baseline.

3. Is this ruling’s proposal preferable to the current ad hoc procurement order process? Why or why not? Compare and contrast benefits and costs as directly as possible.

A key benefit of an RCPPP should be clear certainty for future procurement requirements established at a regular cadence using a defined methodology. From a planning perspective, predictable procurement processes are better for LSEs over rushed and unpredictable ones. As described above, however, Option 3 is likely subject to the same flaws as the previous ad hoc procurement order structure. This is because Option 3 would impose overlapping and potentially inconsistent obligations under RCPPP, RA, and RPS—with the LSE bearing nearly all execution, stranded-cost, development, and penalty risk. Further, it limits flexibility in LSE’s ability to procure, provides leverage to suppliers to negotiate unreasonable terms or exert market power, compresses procurement timelines for LLT resources, perpetuates uncertainty via shifting mELCCs, and fails to account for uncertainty in the load forecast. These flaws negate the potential benefits of an RCPPP.

4. **Are there other proposals already under consideration that better make the connection between long-term resource and transmission planning and LSE resource procurement? If so, which ones, and why? Compare and contrast benefits and costs as directly as possible.**

Just because Option 3 aligns with the PSP planning process, does not mean that it is feasible from a procurement perspective. LSEs include resources in their IRP plans to signal interest in developing their portfolio, but whether they can, depends on many factors. These factors include whether cost assumptions materialize, whether transmission is built to support it, whether the supply chain is sufficient, and whether the project can be sited, licensed, and financed.

Creating a strict compliance program around forward planning processes based on uncertain assumptions will not result in the most cost-effective outcomes for customers or enable California to meet its decarbonization goals at least-cost. Past procurement orders have defined requirements by resource attributes in such a way that necessitates that LSEs procure from a limited pool of projects and suppliers. This creates leverage for suppliers to raise prices or demand unreasonable terms and conditions, and subjects LSEs to potential market power and risks of non-compliance due to limited resource availability. For these reasons, the Commission should retain the original purpose of the PSP – to inform the TPP – rather than create binding procurement requirements.

5. **If the Commission were to implement the proposal in this ruling, should the need determination be based on specific identified resources or resource attributes? How (in general) and how (specifically) should the procurement need be expressed?**

As described above, the Commission should not establish resource- or attribute-specific procurement requirements. The Commission should establish procurement requirements in a technology-neutral manner using the adopted accreditation methodology, preferably SOD. This

will allow LSEs to conduct procurement in an affordable manner given resources' cost and availability in the market.

CalCCA is strongly opposed to resource- or attribute-specific procurement requirements. If specific resources or attributes are specified, the Commission should first conduct a feasibility study to ensure sufficient resources are available within the timeline of the compliance period for LSEs to procure competitively. Transmission needs to be available for location-constrained resources, multiple developers need to be competitively developing resource types, and permitting and supply chain constraints need to be surmountable before ordering prescriptive procurement. Otherwise, it will likely be infeasible for all LSEs to meet their requirements.

6. Comment on whether this ruling's proposal is workable in its relationship to any potential CPE procurement for LLT resources.

As drafted, Option 3 is not workable in its relationship to potential CPE procurement because it is missing key elements needed to provide LSEs certainty about how CPE actions and procurement outcomes will impact their portfolios and obligations. Any CPE procurement for LLT should be reduced from the RCPPP need determination. LSEs should be informed of CPE procurement actions and how such actions affect their requirements sufficiently in advance for LSEs to account for these actions in their procurement. In addition, any RCPPP framework must provide ratepayer protections and assurances that LSEs will not be found out of compliance for deficiencies resulting from CPE failures.

7. Comment on the proposal for a smaller buffer than included in the Staff Proposal from April 2025.

For the reasons described in Section V.A., the Commission should not adopt a buffer. Instead, the Commission should rely on LSE-level risk management and the compliance enforcement program. LSEs account for risk of project delays in their own procurement plans to mitigate against the risk of non-compliance penalties. LSEs are better equipped to mitigate the

risk of project delays because how they mitigate this risk will depend upon the projects in their own portfolios. Generic buffers applied to all LSEs will fail to account for the differences in LSE portfolios and the level of COD delay-risks associated with these portfolios.

8. Is it appropriate to require the LSEs to procure resource and/or resource attributes with minimum and maximum levels within a range (e.g., 80-120 percent, 40-150 percent)? Propose appropriate minimum and maximum ranges, provide your rationale, and/or explain why this proposal is unworkable.

The Commission should not require LSEs to procure on a resource/attribute specific basis for the reasons described above. The planning and development landscape for new resources has many moving parts, interdependent processes, and constraints that require flexibility to ensure targets can be met in an affordable manner. Requiring minimum and maximum levels of procurement tied to the PSP ignores the unpredictable nature of the new resource development process and reduces LSE autonomy to manage their portfolios, based on what is needed and what is available. The analysis in Section III provides a clear demonstration of why resource/attribute specific procurement ranges are problematic.

While ranges may help address the concern with the shifting ELCCs, the need to adjust volumes of procurement on a short timeline in response to ELCC changes would result in inefficiencies and higher costs. More helpful, though, would be flexibility in the timing by which resources must be online. The Commission should learn from the success of the RPS program and provide for rolling average compliance requirements over a multi-year period instead of requiring an exact COD date. The latter grants developers with projects further along the queue market power and harms affordability.

9. Comment on this ruling's proposal for need allocation to specific LSEs.

As described above, Option 3 will continue the practice of allocating new resource needs to LSEs based on load-ratio share, ignoring individual LSE portfolio needs and failing to allow

LSEs to effectively manage load forecast uncertainty. Option 3's ability to trade, sell, or carry over excess procurement does not adequately address stranded cost risks. If the statewide load forecast is overstated, the result could be systemwide over-procurement rather than excess procurement by individual LSEs.

As described in Section IV., these concerns are best addressed by Option 1, in which the Commission would allocate total needs to LSEs. However, if the Commission adopts Option 2, the Commission should: (1) establish a separate process for allocating data center load; (2) allocate the new resource need based on load ratio share during the compliance year; allocate indicative allocations for needs beyond five years forward; and (4) provide LSEs with their allocations confidentially.

10. Comment on the proposed requirement for 100 percent of required resources to be under contract three years out.

Under Option 1 + CES, the Commission should rely on the existing RA and RPS compliance programs, as the RCPPP requirements would be in alignment with these existing programs. Notably, the RA program only requires 90 percent of an LSE's requirement to be under contract in the year-ahead. A multi-year RA framework with gradually increasing compliance obligations as needs get closer will allow LSEs to adjust their procurement strategies as their allocations change due to changes in the load forecast. Locking in 100 percent compliance too far in advance hinders LSEs' ability to accommodate these changes.

Under Option 2 or Option 3, as described in Section V.C.5 above, the Commission should not assess penalties for both contracting deficiencies and COD deficiencies, as this would result in multiple penalties, which are ultimately paid for by customers, for the same deficiency. For a new resource requirement framework, the final assessment of compliance is whether a resource reached COD. When the contract was signed is not relevant as long as the resource

comes online when required. Therefore, the Commission should require reporting on contract status and only assess penalties for COD non-compliance. If the Commission does adopt a penalty for non-compliance with contracting requirements, the Commission should adopt a process for LSEs to demonstrate alternative compliance and good faith efforts to comply before the Commission assesses penalties.

11. Comment on the proposed requirement for 100 percent of required resources to be online within five years from the date the need is identified and allocated.

Resource development timelines are increasing, such that five years between need identification and COD is likely insufficient for an orderly procurement process.⁶⁰ This is especially true if the Commission orders procurement of LLT resources, since LLT resources take longer than five years to develop. For these reasons, the Commission should refrain from adopting resource- or attribute-specific procurement orders and allocate non-binding, indicative allocations to LSEs for years five through ten to help LSEs better plan for future needs that can be met through LLT procurement.

12. Comment on the reasonable of the proposed cadence and sequencing of work to support the proposed framework, including (but not necessarily limited to) ELCC development, net CONE calculation, and procurement data filings.

Net CONE should be periodically updated through a clear process and regular schedule to ensure that the penalty reflects relevant market conditions and adequately incentivizes compliance. While CalCCA continues to advocate for SOD accounting due in part to its more stable nature, if the Commission moves forward with ELCCs, ELCC values should be provided at the same time LSEs are allocated their procurement requirements at the latest, and then they

⁶⁰ “The time projects spend in queues before reaching COD is increasing. For the regions with available data, the median duration from [Interconnection Request] to COD was over 5 years for projects built in 2025.” See Lawrence Berkeley National Lab, *Queued Up: 2026 Edition* (June 2026), <https://emp.lbl.gov/sites/default/files/2026-06/Queued%20Up%202026%20Edition.pdf>.

should be fixed for the compliance period. LSEs require this time and certainty to strategize for the best resource fit for their portfolio and RCPPP requirements and then subsequently source and contract for those resources.

13. Comment on the reasonableness of using marginal ELCC accreditation toward the procurement requirements for the resources identified in this proposal.

For the reasons described above, the Commission should use SOD accreditation rather than marginal ELCC. Inconsistent planning standards between RCPPP and the RA program will lead to higher costs for ratepayers because LSEs will always need to procure to the higher of the two standards to comply, without incremental reliability or clean energy benefits. RCPPP planning and procurement should therefore set the system up for compliance with the ultimate reliability metric – RA SOD requirements.

In addition, the SOD program will be more stable and transparent than a mELCC-based program. ELCCs are widely moving targets, and LSEs could easily contract with a resource that does not have the same compliance value as when the contract was executed. Trying to hit a moving target makes compliance complicated and potentially costly.

14. Comment on the proposal to penalize non-compliance with online resource requirements using a net CONE calculation.

Under Option 1 + CES, the Commission should rely on the existing RA and RPS penalty structures to incent compliance, as the RCPPP requirements would be in alignment with these existing programs.

Under Option 2, the Commission should maintain the use of Net CONE as the basis for any penalty for procurement non-compliance. The Commission introduced Net CONE as the basis for the penalty in D.21-06-035.⁶¹ Net CONE represents the cost of developing a new

⁶¹ D.21-06-035, COL 26.

resource, aligning with the purpose of Option 2, and tracks market conditions to ensure the penalty price adequately incents compliance without being overly punitive. The Commission should establish a regular cadence and transparent process for updating Net CONE so that LSEs have a clear understanding of the penalty amount for each tranche of procurement ordered.

The application of Net CONE penalties should occur after LSEs have an opportunity to use the alternative compliance pathway adopted in D.21-06-035 and demonstrate good faith efforts they have taken to comply.⁶² Unforeseen or extraordinary circumstances can affect procurement over a multi-year horizon, as there are many factors outside the control of LSEs and potentially developers that can impact project viability and timelines. For example, a project may experience a sudden cancellation just prior to a compliance deadline, necessitating an LSE to execute a new contract to replace it. This situation could occur even if the LSE conducted robust procurement outreach, bid review, and vetting of counterparties. In addition, when LSEs have procurement requirements for “resource attributes” that can only be met by a limited set of technologies that are not abundantly available in the pipeline. LSEs may need to rely on alternative compliance approaches and demonstrations of good faith efforts until contracts can be executed for these difficult-to-procure technologies.

A compliance program that lacks flexibility to account for circumstances outside an LSE’s control can unnecessarily increase costs to ratepayers by forcing excess procurement or triggering penalty costs to address temporary gaps that are expected to be resolved in the near-term further it can create opportunities for sellers to exercise market power by incentivizing

⁶² D.25-09-007 provides an alternative compliance pathway in which an LSE will be deemed in compliance with all of the procurement requirements of D.21-06-035 and D.23-02-040, as modified by D.24-02-047, if the LSE demonstrates the following: (1) the LSE sufficiently executed long term contracts that meet the applicable MTR procurement requirement; and (2) the LSE has met its month-ahead system RA requirement for each month that the procurement is delayed, by the deadline for any RA deficiency.

LSEs to secure compliance at any cost. For these reasons, if the Commission adopts Option 2, it should extend the alternative compliance pathway adopted in D.25-09-007 and adopt a good faith efforts process so that LSEs are not penalized for circumstances outside their control.

15. Comment on the proposal to penalize failure to procure a minimum of non-lowest-cost resource procurement at the level of the highest-cost marginal resource.

The Commission should reject this proposal. It would invite suppliers to offer high prices knowing that LSEs would either have to choose between contracting with them or pay penalties based on the highest marginal cost. These cost impacts are unnecessary, given the SOD or mELCC-based requirements and accounting are intended to recognize the different reliability value provided by different technologies. The Commission should refrain from adopting unnecessary compliance elements that will provide leverage to suppliers and influence market prices. Otherwise, RCPPP compliance will not be affordable for customers.

16. Comment on the proposal to penalize non-compliance with contracting requirements with an administrative penalty and suggest a basis for this calculation.

See response to Question 10.

17. Comment on the proposal to move to a four-year interval for consideration of individual LSE IRPs.

CalCCA does not oppose moving to a four-year interval for consideration of individual LSE IRPs if the Commission has an adequate process for obtaining information used to develop the PSP and TPP portfolios more frequently. The inputs and assumptions driving the portfolios, and resulting outputs, change quickly (*e.g.*, ELCCs, load forecast, resource cost assumptions). Four years is too long to go without updating the information used to drive expected infrastructure needs.

LSEs are increasingly engaging with developers well before contracting through, for example, the Interconnection Process Enhancements points allocation, letters of intent, and strategic initiatives like the Sonoma Clean Power GeoZone initiative.⁶³ Individual LSE IRPs provide LSEs the opportunity to communicate their latest views of infrastructure needs based upon this engagement. If individual LSE IRPs are filed every four years, the Commission should establish a separate forum for LSEs to signal their transmission needs for strategic procurement needs in the two-year transmission guidance cycle. In addition, the Commission should use the monthly procurement status reports, and other procurement-related filings such as the RPS procurement status reports, submitted by LSEs to retain a live database of resources under contract. This will provide a more efficient mechanism for the Commission to track procurement and ensure these resources are appropriately represented in the PSP for both transmission planning and procurement requirements.

18. Comment on the relationship of this proposal to the FERC Order 1920 proposals.

CalCCA supports efforts to align IRP planning with processes resulting from FERC Order 1920 compliance. A two-year cycle for the PSP would enable more strategic analysis of transmission needs, including more advanced modeling tools such as decision-making under uncertainty. It would also align with the CAISO's FERC 1920 process, which will only provide policy transmission guidance every other year.

That said, CalCCA does not support tying RCPPP procurement obligations to the PSP and therefore does not comment on RCPPP's relationship to FERC Order 1920.

⁶³ See Sonoma Clean Power website describing the GeoZone initiative, <https://sonomacleanpower.org/geozone>.

19. Comment on the relationship of this proposal to the RA program.

Option 3 is incompatible with the RA program. The result of this incompatibility is economic inefficiencies and increased costs driven by forcing LSEs to procure to two different binding standards. Option 3 “assumes that LSEs are fully capable of managing their portfolios to ensure compliance with both an RCPPP long-term requirement and an RA short-term requirement, even if the details of the compliance and accounting methods are different.” However, LSEs have limited flexibility to optimize their portfolios across the two requirements and minimize economic inefficiencies given the rigidity of Option 3, especially if the Commission requires resource- or attribute-specific procurement. The Commission has designed the RA Program to meet the reliability needs of the grid in operations and should ensure the future RCPPP has strong alignment with this program to maximize efficient and cost-effective procurement.

20. Comment on the relationship of this proposal to the RPS program.

There is no relationship between Option 3 and the RPS program. The RPS program assesses energy production, not new capacity build. As described above, this lack of alignment is misguided. The Commission should seek to align the RCPPP with the RPS program by adopting a clean energy standard that continually progresses zero-carbon energy production requirements on a trajectory that achieves SB 100.

21. Please comment on anything else that is not already covered in the list above.

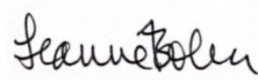
For all the foregoing reasons, CalCCA strongly recommends the Commission reject Option 3. If the Commission declines to adopt CalCCA’s recommendation, the Commission should, at minimum, not implement Option 3 until the next IRP cycle (*i.e.*, once the next LSE IRPs are filed). LSEs developed their 2026 IRPs before the Commission issued Option 3 as a potential RCPPP framework. As discussed above, the knowledge that the PSP will be binding would likely impact the IRPs submitted by LSEs to account for the probability of a resource

becoming commercially operational, in addition to factors such as the resource's fit within its portfolio, future prices, and other considerations.

VIII. CONCLUSION

CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Leanne Bober", is centered on the page.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

August 14, 2026



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

FILED

08/14/26

04:59 PM

R2510003

Order Instituting Rulemaking to Oversee the
Resource Adequacy Program, Consider
Program Reforms and Refinements, and
Establish Forward Resource Adequacy
Procurement Obligations.

R.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 2
LOSS OF LOAD EXPECTATION STUDY AND PRM PROPOSALS**

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August 14, 2026

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SUMMARY OF RECOMMENDATIONS¹

The Commission should:

- Incorporate into the Commission's LOLE study CalCCA's step-by-step methodology for developing risk-reserve curves that can be used to find PRMs that achieve the 0.1 LOLE reliability standard at least cost; and
- Eliminate the effective PRM, which drives up RA costs and allows the Commission to deviate from a 0.1 LOLE standard, among other challenges, in favor of one standard PRM for all LSEs based on robust LOLE modeling.

¹ Acronyms used herein are defined in the body of this document.

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

Order Instituting Rulemaking to Oversee the
Resource Adequacy Program, Consider
Program Reforms and Refinements, and
Establish Forward Resource Adequacy
Procurement Obligations.

R.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 2
PROPOSALS AND LOSS OF LOAD EXPECTATION STUDY**

California Community Choice Association² (CalCCA) submits these planning reserve margin (PRM) proposals pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*³ (Ruling), dated December 12, 2025, and *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*,⁴ dated March 30, 2026.

I. INTRODUCTION

Track 2 of the Resource Adequacy (RA) proceeding takes on complex issues with significant implications for the reliability and affordability of the RA program. Incorporated into Track 2 are updates to the Loss of Load Expectation (LOLE) study used to set the PRM and

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, 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, Valley Clean Energy, and WestLight Energy.

³ *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M590/K884/590884355.PDF>.

⁴ *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, R.25-10-003 (Mar. 30, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K465/603465636.PDF>.

proposed updates to the PRM. CalCCA appreciates the opportunity to submit the following LOLE study and PRM proposals, intended to strengthen the reliability and affordability of the RA program.

First, CalCCA submits into the record a LOLE study for the California Public Utilities Commission (Commission) and parties to consider in parallel with the Energy Division Staff LOLE study. CalCCA's study implements the methodology introduced in CalCCA's June 5, 2026, filing recommending the Commission incorporate alternative inputs and assumptions and an alternative study methodology considering reliability and cost.⁵ This methodology recognizes that there are multiple approaches to achieve a 0.1 LOLE standard and identifies the most cost-effective approach for doing so. The process proposed herein solves an optimization problem that determines how much accredited capacity needs to be shown in each month to achieve reliability at least cost (referred to herein as the PRM Problem) by: (1) developing risk-reserve curves for each month from pairing many different portfolios' accredited capacity with their LOLE; and (2) using monthly RA prices, monthly 1-in-2 peak demand, and the monthly risk-reserve curves to solve the PRM Problem. The Commission should adopt this methodology to ensure that the adopted PRM both: (1) achieves the reliability target; and (2) does so at least cost.

Second, CalCCA proposes that the Commission eliminate the "effective" PRM. The effective PRM, originally adopted in Decision (D.) 21-03-056, authorizes the investor-owned utilities (IOU) to procure RA on behalf of all customers.⁶ The effective PRM should be removed

⁵ *California Community Choice Association's Alternative Inputs & Assumptions Document in Response to Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, R.25-10-003 (June 5, 2026) (CalCCA Alternative I&A Document), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K216/608216359.PDF>.

⁶ D.21-03-056, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, R.20-11-003 (Mar. 25, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M373/K745/373745051.PDF>.

because it: (1) adds demand to the RA market, driving up costs when RA supply is tight; (2) allows the Commission to deviate from the 0.1 LOLE standard in an arbitrary manner; (3) creates an uneven playing field across LSEs by directing the IOUs to procure the effective PRM requirement and allocating the costs of the procurement to all LSEs; (4) does not allow the CAISO to backstop for RA deficiencies; and (5) encroaches on CCA procurement autonomy authorized by statute. Rather than continuing this flawed approach to ensuring reliability, the Commission should remove the effective PRM and instead adopt a single PRM for all LSEs that meets a pre-defined reliability standard informed by thorough review and discussion of the Commission and parties' LOLE studies.

In summary, the Commission should:

- Incorporate into the Commission's LOLE study CalCCA's step-by-step methodology for developing risk-reserve curves that can be used to find PRMs that achieve the 0.1 LOLE reliability standard at least cost; and
- Eliminate the effective PRM, which drives up RA costs and allows the Commission to deviate from a 0.1 LOLE standard, among other challenges, in favor of one standard PRM for all LSEs based on robust LOLE modeling.

II. THE COMMISSION'S LOLE STUDY SHOULD INCORPORATE A METHODOLOGY FOR SETTING THE PRM THAT ACHIEVES THE 0.1 LOLE RELIABILITY STANDARD AT LEAST COST

The Commission should establish a consistent and logical process for setting the PRM that maintains the current requirement of meeting a 0.1 LOLE reliability standard and adds an objective of doing so at least cost. Historically, the lack of a clear pathway from the LOLE study to a PRM has frustrated policy discussions, as was apparent in the 2026 PRM process.⁷ The

⁷ See D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, R.23-10-011 (June 26, 2025), at 32 ("As parties have noted, there is no consensus among stakeholders as to which PRM proposal should be adopted and parties advocate for a wide range of solutions. Several parties express uncertainty and a lack of confidence in Energy Division's LOLE study results and revisions, and recommend that Energy Division continue developing and vetting the LOLE modeling. These robust stakeholder discussions

process proposed herein develops a constrained optimization problem that determines how much accredited capacity needs to be shown in each month to achieve reliability at least cost (referred to herein as the PRM Problem) by: (1) developing risk-reserve curves for each month by pairing many different portfolios' accredited capacity with their LOLE; and (2) using monthly RA prices, monthly 1-in-2 peak demand, and the monthly risk-reserve curves to solve the PRM Problem. These steps, and how they compare to Energy Division's approach, are described in detail in the CalCCA Alternative I&A Document.

The methodology used in CalCCA's LOLE study provides a firm foundation to anchor policy discussions on the most cost-effective way to set PRMs for the 2028 RA program. Key to this process is the development of monthly risk-reserve curves, developed using repeated runs of probabilistic reliability models like SERVIM and the translation of each individual resource portfolio into monthly accredited capacity based on the Slice-of-Day (SOD) rules. These risk-reserve curves provide a straightforward framework for evaluating a variety of PRM-setting proposals.

CalCCA presents the results of its study methodology in three ways: (1) least-cost monthly PRMs assuming monthly RA costs; (2) least-cost monthly PRMs assuming annual RA costs; and (3) an annual PRM. At this stage, CalCCA does not put forward a specific recommendation for the PRM using one of these three options. Instead, CalCCA provides the methodology for the Commission to incorporate into its own studies, seeks to discuss the results of CalCCA's study in the upcoming workshop, and may put forward a specific PRM recommendation based upon the workshop discussion in CalCCA's Final 2028 LOLE Study to be filed in October 2026.

about Energy Division's LOLE studies further demonstrate the complexity of the LOLE modeling, as well as how these types of studies are highly sensitive to inputs.”).

A. CalCCA's LOLE Study Methodology

1. Simulate the LOLE of the Baseline Portfolio

CalCCA created a probabilistic reliability model of the California Independent System Operator (CAISO) system for 2028 using Energy Exemplar's PLEXOS energy modeling software. This model uses a detailed hourly representation of resource availability, energy storage dispatch, load, operating reserve requirements, and import availability to quantify the LOLE for each month. CalCCA simulated the LOLE of the baseline portfolio of resources, R_B , with the following key assumptions and data sources:

- Load:
 - CAISO hourly net managed load profiles based on the Commission's 25 weather years;⁸ and
 - Load forecast uncertainty represented by five discrete outcomes spanning -2 percent to +2 percent, with probability of each outcome from a Midcontinent Independent System Operator (MISO) study.⁹
- Operating Reserves:
 - Operating reserves include 3 percent of hourly net managed load for spinning reserves and 3 percent for regulation up reserves, load shed to maintain reserves;¹⁰ and
 - Storage must maintain sufficient energy to sustain spinning reserve deployment for one hour and regulation up reserves for ten minutes.¹¹

⁸ CAISO net managed load created by summing the "NetLoad" columns for the "PGE", "SCE", and "SDGE" regions. Data included Hourly load components for California regions only, 2000-2024 weather, medians consistent with 2025 IEPR demand forecast Planning Scenario, 2028. *See* CPUC System Reliability Modeling Datasets, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026>.

⁹ *See* CalCCA Alternative I&A Document, at 23, Table 2 (Load forecast error based on U.S. economic forecast errors from MISO PRM study).

¹⁰ CalCCA's assumption that load shedding is used to preserve operating reserves equivalent to 6 percent of the managed net load is consistent with the Commission's modeling requirement that resources must maintain regulating reserves at 3 percent of load in addition to spinning reserves at 3 percent of load. *See Revised Inputs & Assumptions SERVVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)* (June 5, 2026) (CPUC I&A), at 39-40, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF>.

¹¹ CalCCA's requirement that storage must have energy stored sufficient to maintain the provision of operating reserves is similar to the Commission's definition that "[f]or storage resources, the

- Conventional Resources and Energy Storage:
 - Resource categories represented by sets of identically sized units, with each unit having a unique forced outage profile;¹²
 - Forced outages simulated using category-specific forced outage rates from the Commission¹³ and assuming 24-hour mean repair time;
 - 3,125 random samples of forced outages (25 for each weather year and load forecast error combination);¹⁴
 - Category-average thermal derates modeled using hourly weather-dependent derate profiles based on Commission’s 25 weather years;¹⁵ and
 - Battery duration based on the average duration of all CAISO battery storage in the Commission’s June 2026 Baseline Generating List, with pumped hydro storage duration assumed to be 10 hours.
- Variable and Hydro Resources:
 - Variable Energy Resource (VER) output represented through weather-dependent production profiles without separate forced outage modeling, based on Commission’s 25 weather years;¹⁶

operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability.” See CPUC I&A, at 38. However, the Commission does not define the time period over which the reserves must be able to be deployed to calculate the energy availability.

¹² The capacity of each identical unit is the total nameplate capacity of the category divided by the number of units in the category. The nameplate capacity and count of units are from the “Value” column in the “SERVM Units UCAP” tab of the Commission’s UCAP-Adjusted PRM Calibration Workbook for January 23, 2026 (PRM Calibration Workbook), downloaded from: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history>. CalCCA adjusted the PRM Calibration Workbook to include additional capacity needed to align with the Commission’s Baseline Generator List from June 2026, downloaded from: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026>.

¹³ Category-average forced outage rates are from the “EFFECTIVE EFORD EXCLUDING AMBIENT DUE TO TEMPERATURE” column of the “Resource Type UCAP” tab in the PRM Calibration Workbook.

¹⁴ CalCCA’s choice of 25 outage patterns for each unique combination of weather years and load forecast error is consistent with the Commission’s proposed choice of simulating 25 outage patterns. See CPUC I&A, at 47.

¹⁵ CalCCA used the nameplate capacity of each unit to create a capacity-weighted average of the thermal derate by category. Individual unit thermal derates by year are from the Commission’s Ambient Temperature Output Derating, 2000-2024 weather, downloaded from <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026>.

¹⁶ VER profiles are consistent with the PRM Accreditation Workbook categories created by summing the columns for the “PGE”, “SCE”, and “SDGE” regions. See Variable Gen Hourly Profiles, 2000-2024 weather, Baseline Generator List, 2028, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026>.

- Hydro constrained by weather-dependent capacity, monthly energy budgets, and minimum flow requirements;¹⁷ and
- Emergency hydro, additional hydro capacity that can be called on for limited events, has a maximum capacity that varies with month and year based on the Commission's 25 weather years.¹⁸
- Transmission:
 - Internal CAISO transmission constraints not modeled; and
 - Imports represented by a fixed 4,000 megawatt (MW) import capability without explicit modeling of external system conditions.¹⁹
- Reliability Assessment:
 - Loss-of-load event days²⁰ quantified through probabilistic simulation of weather, load uncertainty, resource availability, and operating reserve requirements.

With these assumptions, CalCCA's modeling is consistent with Energy Division's finding from the 2026 LOLE Study that the baseline portfolio experiences no loss-of-load events in the year.²¹

¹⁷ Hydro parameters created by summing each variable for the "PGE_Hydro_V0024", "SCE_Hydro_V0024", and "SCE_Hoover_Hydro_V0024" unit names in SERVVM Hydro Variables, 2000-2024 hydro conditions, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026>. PLEXOS uses a mid-term (MT) schedule to create a coarse plan for allocating hydro across the month based on a load duration curve with 15 blocks. The short-term (ST) schedule then refines the hydro dispatch based on observed hourly conditions.

¹⁸ Emergency hydro capacity created by summing the "capmax" variable for "PGE_Emergency_Hydro_V0024" and "SCE_Emergency_Hydro_V0024" unit names. The maximum energy that can be used by emergency hydro each month is from the corresponding "max_flex" global variable. To model the "borrowing" of emergency hydro energy from the normal hydro budget, CalCCA imposed a constraint that the normal and emergency hydro generation must not exceed the total monthly energy in the "hydro_energy" variable.

¹⁹ CalCCA's assumption of 4,000 MW of import capability is consistent with the Commission's decision to apply a 4,000 MW simultaneous import constraint to all months of the year. *See* CPUC I&A, at 42. Whereas the Commission applies that cap to only some hours and allows potentially greater imports in other hours, CalCCA keeps the cap in all hours because we do not explicitly model the supply and demand balance outside of the CAISO region.

²⁰ Consistent with our understanding of the Commission's approach, we assume that any day with unserved energy counts as one loss of load event. The monthly LOLE is the probability-weighted average count of events across all days of the month. The LOLE across the year is the sum of each month's LOLE. The reliability standard is to meet a 0.1 LOLE across the year.

²¹ *Administrative Law Judge's Ruling on Energy Division's Loss of Load Expectation Study*, R.23-10-011 (July 22, 2024), Appendix A at 27, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF>.

For each month of 2028, CalCCA used the Commission’s UCAP-Adjusted PRM Calibration Workbook (PRM Calibration Workbook)²² to calculate the accredited supply of the baseline portfolio and the lowest achieved reserve margin across all hours of the month.²³ The accredited capacity of the baseline portfolio, the peak demand, and the achieved reserve margin are shown in **Error! Reference source not found.**

Table 1
Achieved Reserve Margin and Loss of Load Expectation of Baseline Portfolio

Month of the year	Monthly accredited capacity of baseline resource portfolio, R_B in tightest hour ²⁴ (MW)	Monthly 1-in-2 peak demand for 2028 in tightest hour (MW)	Monthly achieved reserve margin (%) for R_B , based on K_m and D_{50}^m in tightest hour	LOLE for baseline portfolio, R_B
m	K_m	D_{50}^m	α_m	$LOLE_m$
1	41,598	24,161	72.17	0.000
2	44,902	24,836	80.79	0.000
3	41,937	23,024	82.14	0.000
4	45,211	24,609	83.72	0.000
5	47,419	25,411	86.61	0.000
6	44,738	29,109	53.69	0.000
7	67,709	47,588	42.28	0.000
8	43,752	31,083	40.76	0.000
9	63,244	47,465	33.24	0.000
10	40,937	26,531	54.30	0.000
11	41,655	24,529	69.82	0.000
12	42,235	25,619	64.86	0.000

²² The PRM Calibration Workbook includes only 2,500 MW of interchange capacity. To find the accredited capacity of the Baseline portfolio, CalCCA increased the interchange capacity to 4,000 MW, consistent with the PLEXOS modeling assumptions of the baseline portfolio. In addition, CalCCA added capacity to the “SERVM Units UCAP” and “SERVM Units Original” tabs to align with the Commission’s June 2026 Baseline Generating List. CalCCA also updated the managed load in the workbook to use the CEC 2025 IEPR planning forecast for 2028. This is the same managed load used in the 25 weather year load data provided by the Commission.

²³ CalCCA set the Negative Operating Units (NOU) to 0 in the PRM Calibrated Workbook, and then used the “Solve for PRM’s given NOUs” macro to find the accredited capacity of the storage and non-storage resources in the Baseline portfolio. CalCCA calculated the achieved reserve margin in each hour based on the hourly accredited supply and the hourly 1-in-2 demand on a peak day of each month.

²⁴ Tightest hour is the hour of the day with the lowest achieved reserve margin. In cases where multiple hours have the lowest achieved reserve margin, which occurs frequently in this analysis, we use the first of the hours with the lowest achieved reserve margin.

2. Systematically Adjust Accredited Capacity with Negative Operating Units

Using the same PLEXOS model and PRM Calibration Workbook, CalCCA systematically removed capacity from the baseline portfolio to identify the relationship between accredited capacity and LOLE in each month, as described in CalCCA's Alternative I&A.²⁵ In particular, solving the PRM Problem requires an estimate of the risk-reserve curve for each month, inclusive of all achieved reserve margins that yield monthly LOLE between 0 and over 0.1. Systematically removing capacity from the baseline portfolio produces portfolios whose LOLEs range from near zero LOLE in any month to at least 0.1 LOLE in every month.²⁶ For each increment of capacity removed from the baseline portfolio, CalCCA quantified the corresponding monthly LOLE and monthly accredited capacity based on the SOD rules.

In the probabilistic reliability model, we removed capacity from the baseline portfolio by committing a specific amount of capacity to an external market for all hours of each day. In our understanding, the capacity committed to an external market in PLEXOS is equivalent to the negative operating unit (NOU) in SERVIM. We therefore refer to the capacity committed to the external market as NOU capacity.²⁷

We similarly adjust the resource portfolio in the PRM Calibration Workbook by adding the same amount of NOU to the "NOU" tab and rerunning the "Solve for PRM's given NOUs" macro." Running this macro dispatches storage in the resource portfolio to maximize the

²⁵ CalCCA Alternative I&A, at 13.

²⁶ Results below show that even with 19 GW of capacity removed from the baseline portfolio, the LOLE in April remained below 0.1 even with an achieved reserve margin below 15%. CalCCA did not continue to remove additional capacity beyond 19 GW because all the solutions to the PRM Problem involved planning reserve margins in April above 15%. Additional information on April's risk-reserve relationship for reserve margins below 15% would not change the optimal solutions.

²⁷ Committing a specific amount of capacity for all hours of each day to an external market is also equivalent to removing "perfect capacity" from supply.

achieved reserve margin within the SOD accreditation rules. We then calculate the total supply of the resource portfolio as the accredited capacity of storage plus the accredited capacity of the non-storage resources less the NOU capacity. The achieved reserve margin, α_m , is the amount that the accredited supply exceeds the demand as a percentage of demand, using the lowest margin across all hours of the peak day.

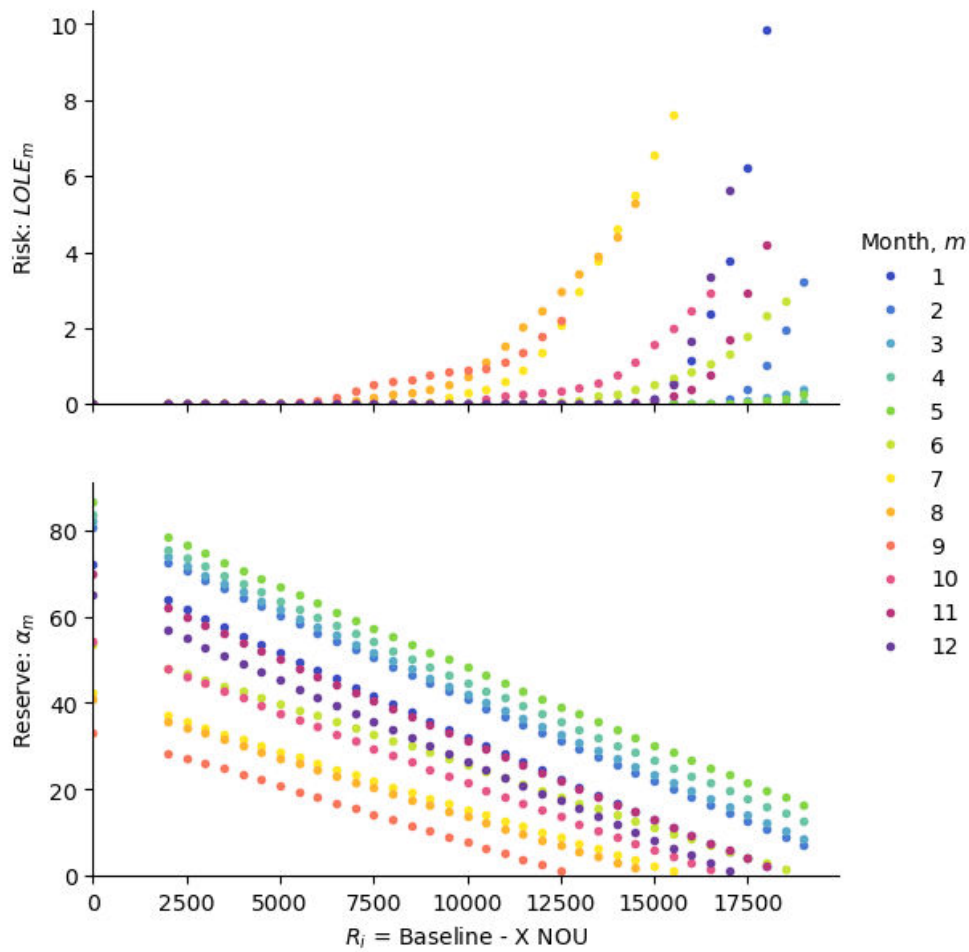
It is important to note that CalCCA's approach treats NOU as a reduction in the amount of supply available to contribute to CAISO reliability rather than an increase in CAISO demand. The decision to treat NOU as a reduction in supply stems from the motivating policy question of determining how much RA supply must be shown in each month to ensure the system is reliable.²⁸ CalCCA's approach contrasts with the Commission's convention of increasing CAISO demand by the NOU, and effectively assuming that every resource in the baseline will be available to CAISO in all months. For the same choice of NOU, the achieved reserve margin with CalCCA's convention of removing capacity from supply will be greater than the achieved reserve margin with the Commission's convention of increasing demand.²⁹ On the other hand, by only making adjustments to the available supply while keeping demand anchored to the CEC IEPR demand forecast, CalCCA's approach means the probabilistic reliability model only requires sufficient operating reserves to meet six percent of CAISO demand, instead of six percent of both NOU and CAISO demand.

²⁸ CalCCA Alternative I&A Document at 6.

²⁹ The achieved reserve margin of a portfolio using CalCCA's convention will exceed the achieved reserve margin of the same portfolio when calculated using the Commission's convention by a factor of $\frac{NOU}{D_{50}^m + NOU}$. Over the range of NOU and demand in the CalCCA analysis, achieved reserve margins can exceed the achieved reserve margins that would be calculated with the Commission's convention by a factor of up to 0.39.

CalCCA evaluated reductions in supply (i.e., NOU) from 2 GW to 19 GW in 500 MW increments in both the probabilistic reliability model (PLEXOS) and the SOD accreditation tool (PRM Calibration Workbook). The resulting monthly risk of the portfolio, as measured by the $LOLE_m$, and the monthly achieved reserve margin, α_m , are shown in **Error! Reference source not found..** Taking more capacity out of the baseline portfolio (i.e., increasing the NOU removed from supply) resulted in increased risk of unmet load and lower achieved reserve margins, though the effects varied by month.

Figure 1
Systematic evaluation of resource portfolios yields the risk ($LOLE_m$) and reserves (α_m) for each month.



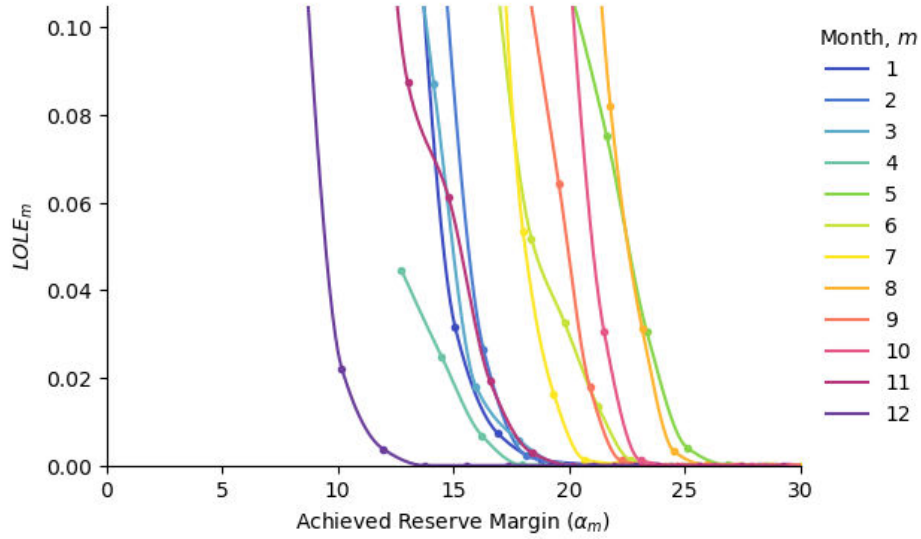
3. Estimate Risk-Reserve Curves for Each Month

For each resource portfolio, the pairing of the resulting risk of unmet load and the achieved reserve margin from **Error! Reference source not found.** creates a point on a monthly risk-reserve curve, shown as the dots in **Figure 2**. In the CalCCA Alternative I&A Document, we initially proposed fitting a parametric function such as a double exponential to approximate the risk-reserve curves.³⁰ The data from the detailed probabilistic reliability model and SOD accreditation rules, however, shows that the risk-reserve relationship is difficult to capture with a simple parametric function. Instead, we use a spline fit³¹ to interpolate between the actual data points, resulting in functions that closely approximate the relationship between risk and reserves in all months, $LOLE_m \sim \widehat{f}_m(\alpha_m)$, as shown in **Figure 2**.

³⁰ CalCCA Alternative I&A Document, at 15.

³¹ Interpolation between datapoints in the risk-reserve curves used the “Piecewise Cubic Hermite Interpolating Polynomial” approach implemented in the Scipy.interpolate package in the PchipInterpolator class. *See* Scipy API, Scipy.interpolate.PchipInterpolator (2008), <https://docs.scipy.org/doc/scipy/reference/generated/scipy.interpolate.PchipInterpolator.html>. The advantage of this interpolation method over a traditional cubic-spline interpolator is that it preserves monotonicity in the interpolation data and enforces continuity in the slope between points. Monotonicity and continuous slopes make it easier to find the optimum in the optimization function used to solve the PRM Problem.

Figure 2
Estimated risk-reserve curve for each month



4. Solve Planning Reserve Margin Problem

With the risk-reserve curves, CalCCA used historical RA market prices to solve for the PRMs that meet the 0.1 LOLE reliability requirement at least cost. The risk-reserve curves allow for an evaluation of several alternative approaches to the problem.

One question that was not addressed in the CalCCA Alternative I&A Document is: which hour of the peak day to use as setting the 1-in-2 peak demand for the purpose of choosing the least-cost PRMs? While the hour with the *highest* demand is a reasonable choice, it is more likely that RA costs depend on the demand in the *tightest* hour (i.e., the hour (or hours) that have the lowest achieved reserve margins in the PRM Calibration Workbook).

In CalCCA's analysis, the demand in the tightest hour was one value for the baseline portfolio, but another value for all other portfolios with anywhere between 2 gigawatts (GW) to 19 GW of NOU. For the remainder of this analysis, we therefore choose the 1-in-2 peak demand in each month to be the peak demand in the tightest hour found in the PRM Calibration Workbook with anywhere between 2 GW to 19 GW of NOU, as shown in **Table 2**. Calculations

of total RA costs also use the RA prices in **Table 2**, based on the Commission’s most recent analysis of the California RA market.³²

Table 2. Peak demand in tightest hour for portfolios with NOU and monthly price of RA Month of the Year	Monthly 1-in-2 peak demand for 2028 in tightest hour with NOU (MW)	Average price for RA capacity (\$/kW-mo)
<i>m</i>	D_{50}^m	p_K^m
1	30,228	5.66
2	29,762	5.66
3	30,316	5.36
4	32,624	5.84
5	32,532	7.13
6	43,089	10.80
7	47,757	17.50
8	46,739	21.43
9	48,356	24.07
10	39,235	11.37
11	32,636	6.51
12	30,849	7.01

Using these RA costs, CalCCA presents three options for solving the PRM problem below: (1) least-cost monthly PRMs assuming monthly RA costs; (2) least-cost monthly PRMs assuming annual RA costs; and (3) an annual PRM.

a. Option 1: Least-Cost Monthly PRMs Assuming Monthly RA Costs

Assuming that the cost of RA depends on the amount of RA capacity procured in each individual month, the PRMs that meet the reliability requirements at least cost are provided through the PRM Problem below.

Choose α_m^* [PRM in each month] to:

³² See CPUC 2023 Resource Adequacy Report (Aug. 2025), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf>.

$$\text{minimize } \sum_m D_{50}^m (1 + \alpha_m) \cdot p_K^m \quad [\text{Least Cost}]$$

$$\text{such that: } \sum_m \widehat{f^m}(\alpha_m) \leq 0.1 \quad [\text{Reliable}]$$

Where:

- D_{50}^m – Peak 1-in-2 managed demand in month m
- α_m – Achieved reserve margin in month m
- p_K^m – Price of accredited capacity in month m
- $\widehat{f^m}(\alpha_m)$ – Risk-reserve curve relating achieved reserve margin in month m to LOLE in m

CalCCA solved the PRM Problem³³ using the risk-reserve curves, shown above in

Figure 2, and found the monthly PRMs that meet the reliability target of 0.1 LOLE at the lowest RA cost set forth in Table 3.

Table 3
Planning Reserve Margins to Meet Reliability Target at Least Cost Assuming Monthly RA Costs (Option 1)

m	p_K^m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	RA Cost_m	LOLE_m
1	\$ 5.7	30,228	17.6%	35,535	\$ 201,126	0.0044
2	\$ 5.7	29,762	18.0%	35,132	\$ 198,847	0.0027
3	\$ 5.4	30,316	18.5%	35,923	\$ 192,550	0.0031
4	\$ 5.8	32,624	17.1%	38,190	\$ 223,029	0.0025
5	\$ 7.1	32,532	25.0%	40,674	\$ 290,007	0.0044
6	\$ 10.8	43,089	21.2%	52,216	\$ 563,931	0.0142
7	\$ 17.5	47,757	19.1%	56,884	\$ 995,472	0.0204
8	\$ 21.4	46,739	23.8%	57,871	\$ 1,240,179	0.0142
9	\$ 24.1	48,356	20.7%	58,365	\$ 1,404,850	0.0225
10	\$ 11.4	39,235	22.8%	48,173	\$ 547,732	0.0030
11	\$ 6.5	32,636	18.1%	38,555	\$ 250,994	0.0039
12	\$ 7.0	30,849	11.7%	34,472	\$ 241,649	0.0047
					Total RA Cost (\$ 000s/yr)	Total LOLE
					\$ 6,350,368	0.1000

³³ CalCCA formulated the PRM Problem as a constrained optimization model and solved it using the sequential least squares programming (SLSQP) method implemented in the Scipy.optimize.minimize function. See SciPy API, minimize(method='SLSQP'), <https://docs.scipy.org/doc/scipy/reference/optimize.minimize-slsqp.html>. The model solves within seconds on a laptop computer.

b. Option 2: Least-Cost Monthly PRMs Assuming Annual RA Costs

Alternatively, we evaluated the least-cost monthly PRMs assuming that RA costs were based on the highest amount of RA that needed to be purchased in any month. This assumption reflects the fact that RA products are often purchased as annual commitments rather than as distinct, monthly transactions. The formulation of the objective function for the PRM changes to:

Choose α_m^* [PRM in each month] to:

$$\text{minimize } \max_m \{D_{50}^m(1 + \alpha_m)\} \cdot p_k \quad [\text{Least Cost}]$$

$$\text{such that: } \sum_m \widehat{f^m}(\alpha_m) \leq 0.1 \quad [\text{Reliable}]$$

Where:

- p_k – Annual price of accredited capacity

CalCCA solved this reformulated PRM Problem using the same risk-reserve curves, and found the monthly PRMs that meet the reliability target of 0.1 LOLE at the lowest annual RA cost as shown in **Table 4**. In contrast to Option 1, the PRMs assuming annual RA costs lead to a leveling of the required capacity across the months of June through September. PRMs in the other months are higher than in Option 1, though there is no assumed incremental cost of meeting these high PRMs since the amount of capacity in the summer months is still higher than the other high PRM months.

Table 4. Planning Reserve Margins to Meet Reliability Target at Least Cost Assuming Annual RA Costs (Option 2)

m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	LOLE_m
1	30,228	22.5%	37,040	0.0000
2	29,762	20.0%	35,719	-
3	30,316	21.5%	36,828	0.0000
4	32,624	21.4%	39,594	0.0000
5	32,532	30.3%	42,401	0.0000
6	43,089	25.6%	54,103	0.0000
7	47,757	20.8%	57,679	0.0012
8	46,739	23.4%	57,679	0.0247
9	48,356	19.3%	57,679	0.0740
10	39,235	24.8%	48,950	-
11	32,636	20.2%	39,222	0.0000
12	30,849	13.8%	35,101	-
Highest RA Requirement				57,679
Annual RA Price (\$/kW-yr)				\$ 128.3
Total RA Cost (\$ 000s/yr)				\$ 7,402,537

c. Option 3: Annual PRM

Rather than choosing PRMs for each month, the Commission could require that the PRM be equal across all months. When the PRM is constant across all months and the total LOLE across the year is equal to 0.1, there is only one unique solution. For simplicity, CalCCA found this unique solution by adding a constraint requiring the reserve margin α_m to take the same value, α , for all months to the PRM Problem:

$$\alpha_m = \alpha \quad \forall m \in \{1, \dots, 12\} \quad [\text{Annual PRM}]$$

The cost of meeting the annual PRM is higher than allowing monthly PRMs, under either assumption of RA costs that vary by month or RA costs that depend only on the highest capacity procured for the year, set forth in **Table 5**. However, the premium for selecting an annual reserve

margin, rather than monthly reserve margins, is only 1.7 percent assuming monthly RA³⁴ costs, or 2.8 percent assuming annual RA³⁵ costs.

Table 5
Annual Planning Reserve Margin to Meet Reliability Target (Option 3)

m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	LOLE_m
1	30,228	22.7%	37,077	-
2	29,762	22.7%	36,506	-
3	30,316	22.7%	37,185	-
4	32,624	22.7%	40,016	-
5	32,532	22.7%	39,904	0.0475
6	43,089	22.7%	52,853	0.0012
7	47,757	22.7%	58,578	0.0001
8	46,739	22.7%	57,330	0.0461
9	48,356	22.7%	59,313	0.0006
10	39,235	22.7%	48,125	0.0045
11	32,636	22.7%	40,031	-
12	30,849	22.7%	37,839	-
Total RA Cost - Monthly (\$ 000s/yr)			\$ 6,459,223	Total LOLE
Total RA Cost - Annual (\$ 000s/yr)			\$ 7,612,254	0.1000

B. Conclusions and Next Steps

Overall and as stated above, CalCCA submits these options into the record to supplement Energy Division's work with its LOLE study. CalCCA does not put forward a specific recommendation for the PRM using one of these three options at this point. CalCCA looks forward to further discussing these results in the upcoming workshop, and may put forward a

³⁴ Total RA cost with an annual PRM (Option 3), as shown in **Table 5**, is higher than the Total RA cost with monthly PRMs (Option 1), as shown in **Table 3**, assuming RA costs vary by monthly quantity of purchased RA.

³⁵ Total RA cost with an annual PRM (Option 3), as shown in **Table 5**, is higher than the Total RA cost with monthly PRMs (Option 2), as shown in **Table 4**, assuming RA costs vary only with the maximum quantity of purchased RA across the year.

specific PRM recommendation based upon the workshop discussion in CalCCA’s Final 2028 LOLE Study to be filed in October 2026.

III. THE EFFECTIVE PRM SHOULD BE ELIMINATED

The Commission should eliminate the effective PRM in favor of one standard PRM for all LSEs based on robust LOLE modeling. Since 2021, the Commission has relied on the IOUs to procure above their own RA requirements to a non-binding “effective PRM,” allocating the costs of effective PRM procurement to all LSEs.³⁶ This requirement was adopted to meet “a need for an increase in supply side resources in light of the weather experienced throughout the summer of 2020 and in anticipation of more frequent extreme weather events resulting from climate change.”³⁷ However, the current effective PRM is flawed, and should be removed because it: (1) adds demand to the RA market competing for resources non-IOU LSEs need for compliance, driving up costs when RA supply is tight; (2) allows the Commission to deviate from the 0.1 LOLE standard in an arbitrary manner; (3) creates an uneven playing field across LSEs by directing the IOUs to procure the effective PRM requirement and allocating the costs of the procurement to all LSEs; (4) does not allow the CAISO to backstop for RA deficiencies since the CAISO only backstops for a deficiency to the PRM and not the effective PRM; and (5) encroaches on CCA procurement autonomy authorized by statute. Instead, robust and accurate LOLE modeling should be the goal to ensure reliability.

First, the effective PRM can drive up RA prices by adding demand to the RA market, especially during periods when RA supply is tight. 2024, for example, was an extremely tight RA year. CalCCA analysis demonstrates RA demand would potentially exceed supply by almost 900 MW in September 2024 had the IOUs procured to the minimum effective PRM target of 1,700

³⁶ D.21-03-056, (Findings of Fact (FOF) 64-73).

³⁷ *Id.*, FOF 64.

MW.³⁸ The Commission's Excess Resources Reports for 2024 demonstrate that the IOUs procured 995 MW towards the effective PRM.³⁹ In the same year, LSEs were paying RA prices up to \$101 per kW-month, which are prices indicative of market scarcity.⁴⁰ Allowing RA eligible resources to count towards the effective PRM adds competing demand for RA supply. When the available supply is not sufficient for a competitive market that can meet the PRM alone, adding an effective PRM on top of the PRM does not result in incremental reliability. It instead only creates additional, artificial market scarcity leading to inflated prices for all RA capacity (capacity used to meet the PRM and effective PRM) and exacerbates the risk of LSE deficiencies.

Second, the effective PRM allows the Commission to deviate from the 0.1 LOLE standard in an arbitrary manner. The Commission recently adopted Resolution E-5467, authorizing SDG&E utility-owned storage resources for Westside Canal Storage at an estimated cost of \$267.9 million for the effective PRM even though SDG&E already met its effective PRM target.⁴¹ Although SDG&E's effective PRM target was 110-220 MW and SDG&E had already

³⁸ *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs* (Jan. 16, 2024), https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf.

³⁹ PG&E 2024 Excess Resources Report, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/pgeexcess-resource-reporting-d211201509032024.xlsx>; SCE 2024 Excess Resources Report <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/sceexcess-resource-reporting-d211201509302024.xlsx>; and SDG&E 2024 Excess Resources Report, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/sdgeexcess-resource-reporting-d21120150912024.xlsx>.

⁴⁰ CalCCA analysis of Federal Energy Regulatory Commission (FERC) Electric Quarterly Report (EQR) data demonstrates that prices for RA reached over \$100 per kilowatt (kW) -month in 2024. CalCCA observed three transactions (totaling 92 MW) at prices of \$100-101/kW-month for sale of capacity to California LSEs, delivered in 2024. The data source is CalCCA's analysis of EQRs, downloaded from <https://eqrreportviewer.ferc.gov/>.

⁴¹ [Redacted] Resolution E-5467, *San Diego Gas & Electric Company ("SDG&E") request for approval of one local capacity Utility Owned Energy Storage Contract and related costs pursuant to Decision ("D.") 25-06-048* (June 11, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M608/K784/608784221.PDF>.

procured 208.6 MW, SDG&E requested and the Commission authorized effective PRM treatment for the utility-owned storage resources. The result is cost recovery by all LSEs for a utility-owned resource that is not needed to meet SDG&E's effective PRM target. In exceeding the upper bound of the effective PRM, the Commission has demonstrated that it will use the effective PRM to deviate from a defined reliability standard at the expense of ratepayers. The Commission should instead establish one PRM used to set all LSE requirements. This PRM should be based upon a robust LOLE study, vetted by parties, to ensure it meets the 0.1 LOLE target without materially undershooting the PRM and introducing reliability risk or overshooting the PRM and imposing unnecessary costs on ratepayers.

Third, the effective PRM construct creates an uneven playing field across LSEs by directing the IOUs to procure the effective PRM requirement and allocating the costs of the procurement to all LSEs. This allows the IOUs to shift resources between the effective PRM and their bundled portfolio, creating an opportunity for the IOUs to place higher-cost procurement in the effective PRM and recover those costs from all load – including customers that do not take generation service from the IOUs. While provisions allowing the IOUs to move resources between bundled load needs and the effective PRM may protect bundled load customers, they do so by shifting those costs to departed load customers. This asymmetry affords the IOUs a structural advantage unavailable to other LSEs.

Fourth, the effective PRM does not allow the CAISO to backstop for RA deficiencies. The CAISO tariff gives it the authority to cure RA deficiencies, but not for effective PRM deficiencies, raising concerns about the CAISO's ability to ensure reliability when a portion of the RA need is procured via the effective PRM.

Fifth, the effective PRM encroaches on CCA procurement autonomy authorized by statute. The core function of LSEs is to procure for their customers' electricity needs. Reliance on centralized procurement by the IOUs undermines this function. California Public Utilities Code Section 380 states that "[t]he resource adequacy program shall achieve all of the following objectives" including "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers."⁴² The effective PRM runs contrary to this objective by ordering the IOUs to procure RA on behalf of all customers rather than allowing each individual LSE to fully procure the RA necessary to meet their customers' reliability needs.⁴³

For these reasons, the Commission should remove the effective PRM in its entirety. Instead of relying on an effective PRM, the Commission should establish a single PRM for all LSEs through robust LOLE modeling and party input that ensures the RA program meets a 0.1 LOLE standard.

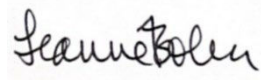
IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the LOLE study methodology and effective PRM proposal herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

⁴² Cal. Pub. Util. Code § 380(b)(5).

⁴³ While Section 380(i) allows the Commission to consider options including a centralized RA mechanism in weighing CCA autonomy among the other factors listed in subsection (h) to find "the most efficient and equitable means" for achieving reliability, CalCCA's recommendation is to focus on robust and accurate modeling instead of relying on a less accurate PRM to meet these objectives. In this manner, the Commission can ensure reliability through all LSEs rather than needing to centralize any part of that procurement.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Leanne Bober", is centered on the page. The signature is written in a cursive, flowing style.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

August 14, 2026

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

Application of Pacific Gas and Electric
Company for Approval of Its Billing
Modernization Initiative

Application No. 24-10-014
(Filed October 23, 2024)

(U 39 M)

**JOINT REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M)
AND THE JOINT COMMUNITY CHOICE AGGREGATORS IN SUPPORT OF
ADOPTION OF THE PARTIAL SETTLEMENT AGREEMENT**

(PUBLIC VERSION)
ATTACHMENT A CONTAINS CONFIDENTIAL INFORMATION

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Dated: August 25, 2026

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

Application of Pacific Gas and Electric
Company for Approval of Its Billing
Modernization Initiative

Application No. 24-10-014
(Filed October 23, 2024)

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ADOPTION OF THE PARTIAL SETTLEMENT AGREEMENT**

**(PUBLIC VERSION)
ATTACHMENT A CONTAINS CONFIDENTIAL INFORMATION**

I. INTRODUCTION

Pursuant to Rule 12.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) and WestLight Energy,¹ Ava Community Energy, Central Coast Community Energy, Marin Clean Energy, City of San José, Silicon Valley Clean Energy, and Sonoma Clean Power Authority (collectively, the Joint CCAs, and together with PG&E, the Settling Parties) submit these comments in reply to the joint comments of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), The Utility Reform Network (TURN), and Small Business Utility Advocates (SBUA) (collectively, the Settlement Opponents) filed August 10, 2026 opposing the cost recovery provisions of the Partial Settlement Agreement filed July 9, 2026 by the Settling Parties (the Partial Settlement Agreement).²

The Settling Parties entered into the Partial Settlement Agreement after fully supporting their litigation positions with written testimony, conducting extensive discovery, and actively negotiating the settlement for nearly a year (including months of weekly/twice-weekly meetings). The Partial Settlement Agreement reflects a balanced compromise that will benefit

¹ Formerly Peninsula Clean Energy Authority.

² Note that the City and County of San Francisco, acting by and through its Public Utilities Commission (CleanPowerSF), joined in the Joint CCAs' June 30, 2025, Direct Testimony submission and its July 30, 2025, Rebuttal Testimony submission. However, CleanPowerSF is not included in the group of Joint CCAs as defined in the Partial Settlement Agreement. CleanPowerSF submitted comments in support of the Partial Settlement Agreement on August 10, 2026.

customers by ensuring that they receive the benefits of a comprehensive billing system upgrade at a reduced cost. It is supported by and reasonable in light of the record in this proceeding, consistent with law, and in the public interest. The Commission should adopt the Partial Settlement Agreement without modification.

The Settlement Opponents' opposition to the Partial Settlement Agreement is rooted in a misunderstanding of the Commission's standard of review for settlements as well as of the scope, substance, and supporting evidence for the Partial Settlement Agreement. In these reply comments, the Settling Parties clarify that:

1. The cost term of the Partial Settlement Agreement is supported by a clear record showing both the urgent need for the Billing Modernization Initiative (BMI) investments (PG&E's testimony and the Joint CCAs' testimony) and detailed cost forecasts (PG&E's testimony);
2. Commission precedent is clear that a cost reduction achieved through settlement need not be itemized to be reasonable;
3. The record supports the \$24 million in incremental costs associated with the settlement proposals, and the Settling Parties seek to provide additional insight into these cost forecasts in this filing;
4. A focus on a broader set of customer concerns does not render the Joint CCAs' perspective "weak" on public interest issues generally or cost reasonableness issues in particular, and in fact the Joint CCAs are uniquely positioned to advocate on behalf of ratepayers on billing investment issues; and
5. The Settling Parties do not argue that any special "presumption" should apply in favor of the Partial Settlement Agreement, and in fact have expressly recognized the discrete scope of this Settlement in that it would not fully resolve the cost issues still being litigated by non-settling parties.

II. THE COST TERMS OF THE PARTIAL SETTLEMENT AGREEMENT ARE REASONABLE

A. The Record Supports Approval of the BMI at the Reduced Price Point Reflected in the Partial Settlement Agreement

The Settlement Opponents cannot reasonably dispute that PG&E's current legacy billing systems are out-of-date and have significant functional shortcomings. Currently, PG&E's outdated legacy billing systems impose functional limitations on how and what critical billing data can be tracked and shared, how quickly PG&E can address data quality issues impacting its own and community choice aggregator (CCA) billing operations, how customer bills are designed and updated, and how the billing process is managed. A modern billing system like C2M will enable PG&E to address these limitations, improve billing service quality to all of its

bundled and unbundled customers, and provide necessary features and data to CCAs that will benefit CCA customers and support competition.³ These are not optional enhancements; they are essential functions of a utility billing system that PG&E must offer to continue to provide reasonable service to its customers and reasonable service to CCAs that rely on PG&E as their billing service provider. The drastic funding cuts proposed by Cal Advocates and TURN would hamstring the C2M upgrade—limiting the functionalities of the new system and significantly reducing customer benefits.⁴ For example, Cal Advocates would cut funding for three of the five modules within C2M, including the Market Transaction Management Module, which is necessary to centrally manage how PG&E’s billing system interacts with CCAs to improve responsiveness and reduce errors.⁵

The Settlement Opponents do not engage with customers’ need for an upgraded billing system or recognize the benefits that will flow to customers from that system. PG&E provided evidence supporting the benefits that will result from the implementation of C2M,⁶ and the Joint CCAs provided evidence of the substantial gaps in PG&E’s billing services under its outdated billing system and the ways in which the BMI design must bridge those gaps.⁷ The implementation of C2M (or a comparable end-state system) is the necessary groundwork for delivering these customer benefits, including those achieved through implementation of portions of the Partial Settlement Agreement.

The Partial Settlement Agreement would allow PG&E to deliver the benefits of C2M, as contemplated in its original Application and Testimony, as well as the incremental design features and functionalities necessary to support CCA customers, all at a significantly reduced cost to customers—specifically, a reduction of approximately \$88 million from PG&E’s original request.⁸ The Joint CCAs and PG&E submit that a final end-state billing system that enables these necessary fixes and improved functionalities is a worthwhile investment for customers at

³ See Joint Reply Br. of PG&E and Joint CCAs, pp. 2-3.

⁴ See PG&E Reply Br., pp. 1-2, 10-13.

⁵ PG&E Reply Br., pp. 12-13 (citing CA-04, p. 8, lines 19-24); PG&E Ex-01, p. 4-39, lines 5-11.

⁶ See PG&E Ex-01, p. 6-12, lines 11-16; p. 6-13, Table 6-4; p. 6-28, lines 3-4; p. 6-31, lines 1-3.

⁷ See Joint CCA Ex-01, p. 11, line 1 to p. 31, line 24; *id.*, p. 48, line 3 to p. 63, line 13.

⁸ The Partial Settlement Agreement sets forth costs for the BMI of \$586,614,000 in capital and \$81,595,000 in expense. This overall forecast encompasses the costs associated with the settlement agreement proposals of \$21,000,000 in capital and \$3,000,000 in expense.

this reduced price point. Importantly, these cost levels are not untethered to the record, as the Settlement Opponents suggest⁹—PG&E submitted briefing explaining in detail why the cost levels in the Partial Settlement Agreement are reasonable, and incorporates those showings by reference here.¹⁰ For all these reasons, the cost terms of the Partial Settlement Agreement are reasonable and are supported by the record.

B. Unallocated Reductions Are Reasonable in Settlement Agreements

The Settlement Opponents challenge the form of the Partial Settlement Agreement more than the substance. They claim that the unallocated reduction to the total cost forecast prevents the Commission from making findings and conclusions on the material issues in this proceeding. This is not the case. The Commission can resolve the factual and legal issues in the proceeding by finding that PG&E has met its burden based on the record evidence and can simultaneously approve the voluntary reduction in the Partial Settlement Agreement.

Further, even if the record evidence presented here did not support the entirety of the costs presented in the Application (as PG&E submits that it does), the Settlement Opponents cite no basis for their contention that an unallocated reduction would “prevent the Commission from fulfilling its duty... to make decisions that contain findings and conclusions on all material issues.”¹¹ In fact, this statement is contrary to Commission precedent, which shows that the reduction need not be itemized based on arguments from non-settling parties.¹² As the Commission explained in approving a past settlement between PG&E and Cal Advocates (which TURN opposed), “there is no requirement that a settlement identify the specific costs that were reduced by an individual program, project, account, or [Catastrophic Event Memorandum Account] event... settlements by nature are to a certain extent ‘black box,’ but nevertheless are

⁹ See Joint Comments of Settlement Opponents, pp. 2-3.

¹⁰ See A.24-10-014, PG&E’s Opening Brief, pp. 11-36 (July 16, 2026); A.24-10-014, PG&E’s Reply Brief, pp. 3-41 (August 13, 2026).

¹¹ Joint Comments of Settlement Opponents, p. 2.

¹² Although the Commission may also decide that the voluntary reduction reflects several of the Commenting Parties’ proposed adjustments. See PG&E Reply Br., p. 2, n. 3.

reasonable when supported by adequate detail.”¹³ It is well-established that “[c]onsistent with judicial and administrative precedent, the Commission’s review of the settlement does not require parceling each fact or issue resolved therein.”¹⁴

C. The \$24 Million Adjustment for the Cost of the Settlement Agreement Proposals is Reasonable

Similarly, the \$24 million incremental cost forecast associated with the settlement agreement proposals is supported by the existing record establishing the necessity of a comprehensive billing system upgrade that addresses the needs of CCA customers—needs that are directly addressed by these settlement agreement proposals. While the Settlement Opponents suggest that the Commission cannot approve this incremental \$24 million request because of a lack of transparency around these cost forecasts, Settlement Opponents made no effort to learn more about these forecasts. Neither PG&E nor the Joint CCAs have received discovery requests about any aspect of the Partial Settlement Agreement, despite the fact that the Settling Parties filed the agreement over a month before the record closed.¹⁵

While the Settling Parties maintain that the record as submitted supports this \$24 million forecast, in the interest of providing parties and the Commission with more insight into how the Settling Parties arrived at these forecasts, the Settling Parties have agreed to provide the cost estimates for the settlement agreement proposals shared during the course of their settlement negotiations. Attachment A (Confidential) contains cost estimates for each of the proposals in the Partial Settlement Agreement.¹⁶

Even accounting for this \$24 million in incremental costs, the overall capital and expense cost forecasts the Settling Parties agree are reasonable in the Partial Settlement Agreement

¹³ D.23-10-025, p. 15 (internal citations omitted); *see also* D.16-10-004, pp. 13-14 (approving a settlement between SoCalGas, TURN, and Cal Advocates that took a “black box” approach to cost allocation issues); D.18-08-013, pp. 25-26 (approving a settlement between PG&E, SBUA, TURN, and others that took a “black box” approach to revenue allocation); D.04-05-055, pp. 3, 79-80 (approving a settlement between PG&E, Cal Advocates, TURN, and others in a PG&E rate case with total amounts for general categories rather than a detailed forecast for each account), *modified on other grounds by* D.05-02-050 and D.05-12-046.

¹⁴ D.26-03-017, p. 13.

¹⁵ A.24-10-014, Assigned Commissioner’s Scoping Memo and Ruling, p. 6 (March 27, 2025) (“The proceeding will stand submitted upon the filing of reply briefs”).

¹⁶ Contemporaneously with this filing, the Settling Parties filed a motion to reopen the record for the purpose of admitting Attachment A.

remain significantly lower—by approximately \$88 million—than PG&E’s original proposal in this proceeding.¹⁷ The record supports adoption of these modified cost forecasts as well as explicit approval of the \$24 million necessary to implement the proposals in the Partial Settlement Agreement.

III. THE COMMISSION SHOULD NOT DISCOUNT JOINT CCAS’ UNIQUE PERSPECTIVE AS RATEPAYER ADVOCATES

The Settlement Opponents suggest that, because the Joint CCAs’ recommended reduction to PG&E’s requested revenue requirement in testimony was smaller than those proposed by the Settlement Opponents, the Commission should not consider the Joint CCA perspective as a legitimate—or equally valuable—ratepayer advocate perspective.¹⁸ This logic is flawed for at least three reasons.

First, a narrow focus on one issue—overall project spend—is one way for a ratepayer advocate to approach the question of whether a utility’s proposed investment in IT infrastructure is in the public interest, but it is not the only valid approach. The Joint CCAs are advocates for the local communities that formed them and the electric customers living in those communities. While CCA charter mission statements vary by CCA, they generally all highlight an intent to serve the public interest through promoting local choice, clean energy, competitive and stable rates, and community benefits. With these policy objectives in mind, the Joint CCAs’ advocacy in this case focused on the cost reasonableness, cost functionalization, *and cost effectiveness* of PG&E’s Application—*i.e.*, ensuring the BMI project is well designed to benefit all customers, including the CCA customers that make up the majority of PG&E’s customer base. A focus on this broader set of customer concerns does not render the Joint CCAs’ perspective unimportant or “weak”¹⁹ on public interest issues generally or cost reasonableness issues in particular; rather, it reflects the more comprehensive lens through which the CCAs approach these kinds of proposed investments on behalf of their customers.

Second, the Joint CCAs are uniquely positioned to advocate on behalf of ratepayers in PG&E’s territory because they are in direct communication with the majority of PG&E’s

¹⁷ PG&E maintains that the full amount of its request is supported by the record. The Joint CCAs recognize support in the record for the cost forecast as adjusted by the Partial Settlement Agreement.

¹⁸ Joint Comments of Settlement Opponents, pp. 3, 5-6.

¹⁹ Joint Comments of Settlement Opponents, pp. 5-6.

customer base (*i.e.*, PG&E's unbundled customers that take service from a CCA provider). CCAs' inherently local scope facilitates more direct access to all aspects of the customer experience—including customer challenges and complaints regarding rate increases, billing errors and delays, confusing bill presentation, and other issues related to the billing experience. The Joint CCAs leveraged this deep understanding of their customers' needs in their advocacy in this case.

Finally, the Joint CCAs' billing and operations teams have direct insight into the nuts and bolts of how billing operations work behind the scenes, how their teams' processes interact with PG&E's, and what system functionalities are needed to improve those processes and coordination between them. To the Joint CCAs' knowledge, this is a perspective that no other intervenor in this proceeding can offer.

In sum, the Joint CCAs leveraged their understanding of the most pressing billing issues facing their customers to comprehensively review PG&E's BMI Application and identify any problematic or underdeveloped aspects of PG&E's proposal. The issues the Joint CCAs identified led to recommendations to address cost reasonableness, cost functionalization, and cost effectiveness concerns. All of the ratepayer advocates in this proceeding bring an important perspective to the table on how the BMI can best serve the public interest; the Joint CCAs bring one such perspective that should not be discounted.

IV. THE SETTLING PARTIES DO NOT RELY ON A PRESUMPTION OF FAVORABILITY AND HAVE CLEARLY EXPLAINED THE SCOPE OF THE PARTIAL SETTLEMENT AGREEMENT

The Settlement Opponents argue that “[a]pplying a presumption of favorability” to the Partial Settlement Agreement “is against the public interest and invites mischief” and that the proposed settlement does not meet “procedural preconditions for presumed favorability.”²⁰ This is a strawman. The Settling Parties at no point argued that any presumption should apply, and there are no “procedural preconditions” that trigger a formal presumption of favorability or “invoke” the public policy favoring settlements.

In support of the Partial Settlement Agreement, the Settling Parties quoted the Commission's statement that there is “a strong public policy favoring settlement of disputes if

²⁰ Joint Comments of Settlement Opponents, p. 5.

they are fair and reasonable in light of the whole record.”²¹ This public policy is not something that can be “invoked,” and is merely a statement about the public policy of the Commission, and indeed of the State of California.²² Importantly, this public policy does not change any standard of the Commission’s review or approval of a settlement. Commission Rule 12.1 sets forth that the Commission may only approve a settlement if it is “reasonable in light of the whole record, consistent with law, and in the public interest[.]”²³ and the Settling Parties believe that the Partial Settlement Agreement should be approved based on that standard.

The Settlement Opponents conflate the Commission’s standard of review for settlements with its standard for recognizing a “presumption of fairness” in the context of settlement. They point to factors from D.26-03-017, including whether “the negotiation is achieved through ‘arm’s-length bargaining,’ is ‘free from collusion’ and whether ‘there is little or no opposition to the settlement.’”²⁴ However, as that decision makes clear, these are elements that a court evaluated in “recogniz[ing] a *presumption of fairness*[.]”²⁵ The Settling Parties have not invoked this presumption because such a presumption only applies when “there is little or no opposition to the settlement[.]” which the Settling Parties have not claimed is the case here.²⁶ The Settling Parties do not argue that the Partial Settlement Agreement is unopposed nor do they invoke the “presumption of fairness,” “presumption of favorability,” or any other presumption.

The Settling Parties have in fact expressly recognized the more limited scope of the Partial Settlement Agreement. They have noted that this is a *partial* settlement—meaning it does not resolve all open issues in the case—because it does not fully resolve cost issues still being litigated by non-settling parties:

²¹ Joint Motion, p. 11 (quoting D.23-10-025, p. 12).

²² See, e.g., *Rheinhardt v. Nissan N. Am., Inc.* (2023) 92 Cal.App.5th 1016, 1027, 309 Cal.Rptr.3d 859 (stating “California has a strong public policy favoring the voluntary settlement of disputes” and citing *Monster Energy Co. v. Schechter* (2019) 7 Cal.5th 781, 793, 249 Cal.Rptr.3d 295, 444 P.3d 97; *Zamora v. Clayborn Contracting Grp., Inc.* (2002) 28 Cal.4th 249, 260, 121 Cal.Rptr.2d 187, 47 P.3d 1056 [“the law favors settlements”]; *Kaufman v. Goldman* (2011) 195 Cal.App.4th 734, 745, 124 Cal.Rptr.3d 555; *Osumi v. Sutton* (2007) 151 Cal.App.4th 1355, 1359, 60 Cal.Rptr.3d 693 [“[i]t is, of course, the strong public policy of this state to encourage the voluntary settlement of litigation”].); *McClure v. McClure* (1893) 100 Cal. 339, 343, 34 P. 822 (“Settlement agreements ’are highly favored as productive of peace and good will in the community, and reducing the expense and persistency of litigation.’”).

²³ Rule 12.1(d).

²⁴ Joint Comments of Settlement Opponents, pp. 5, 6 (citing D. 26-03-017, p. 11).

²⁵ D.26-03-017, p. 11 (emphasis added).

²⁶ D.26-03-017, p. 11.

The Settling Parties acknowledge and agree that the issue of the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts associated with the BMI will not be fully resolved by this Partial Settlement Agreement. This issue is still in dispute in A.24-10-014 among other parties to A.24-10-014 that are not signatories to this Partial Settlement Agreement.²⁷

In fact, the Partial Settlement Agreement makes clear that while it represents an agreement between PG&E and the Joint CCAs that the overall cost forecasts provided in Tables 1 and 2 of the Agreement are reasonable,²⁸ Commission approval of the Settlement would not automatically result in approval of those overall cost forecasts, which are still being litigated by other non-settling parties.²⁹ In other words, in addition to determining whether to approve the Partial Settlement Agreement, the Commission must also make a determination about the reasonableness of PG&E's cost forecasts, as modified by the Partial Settlement Agreement, in light of the full record in this case (which includes Settling Parties' position that these forecasts are just and reasonable as well as the perspectives advanced by non-settling parties).

In the same 2026 decision cited by the Settlement Opponents, the Commission provides that its "role is to ensure that the agreement as a whole meets the criteria of Rule 12.1(d)."³⁰ The various arguments raised by the Settlement Opponents regarding the strength of the Joint CCAs in negotiation, in addition to being baseless as discussed above, are unrelated to the question at hand: whether the Partial Settlement is "reasonable in light of the whole record, consistent with law, and in the public interest" as required by Rule 12.1(d).

²⁷ Partial Settlement Agreement, p. 4.

²⁸ See Partial Settlement Agreement, Section 3.2 ("With this Partial Settlement Agreement, and in light of the compromises reflected therein, the Settling Parties agree that the 2024-2030 total capital expenditure and expense forecasts for the BMI set forth in Table 1 and Table 2 below are reasonable.").

²⁹ See Partial Settlement Agreement, Section 3.2 ("Nothing herein limits or affects the ability of other parties to A.24-10-014 (aside from the Joint CCAs) to litigate the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts associated with the BMI in A.24-10-014.").

³⁰ D.26-03-017, p. 13.

V. CONCLUSION

For the foregoing reasons, the Settling Parties respectfully request that the Commission approve the Partial Settlement Agreement without modification, in accordance with the legal standards set forth in Rule 12 of the Commission's Rules of Practice and Procedure.

Respectfully Submitted,

By: /s/ Aaron J. Lewis
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AGGREGATORS

Dated: August 25, 2026

ATTACHMENT A

(PUBLIC VERSION)

**Attachment A contains confidential material and has been removed its entirety.
The confidential version is filed with the CPUC Docket Office.**

Docket No.: A.26-05-007

Exhibit No.: _____

Date: August 27, 2026

Witness: Ryan Matley

**PREPARED DIRECT TESTIMONY OF RYAN MATLEY
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
IN PACIFIC GAS AND ELECTRIC COMPANY'S
2027 ERRR FORECAST PROCEEDING**

PUBLIC VERSION

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ATTACHMENTS

Attachment RAM-1:	Curriculum Vitae of Ryan Matley
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1 **I. INTRODUCTION AND SUMMARY OF TESTIMONY**

2 The California Community Choice Association (**CalCCA**) presents this direct
3 testimony in the *Application of Pacific Gas and Electric Company for Adoption of Electric*
4 *Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery*
5 *Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas*
6 *Forecast Revenue Return and Reconciliation* (**Application**). This testimony has been
7 prepared on behalf of CalCCA by Ryan Matley, Principal, NewGen Strategies & Solutions.
8 Mr. Matley’s qualifications are set forth in Attachment RAM-1.

9 CalCCA has a particular interest in the Power Charge Indifference Adjustment
10 (**PCIA**) and the Portfolio Allocation Balancing Account (**PABA**), both of which are
11 charged to customers of the 11 community choice aggregators (**CCAs**) that CalCCA
12 represents through the PCIA rates for which Pacific Gas and Electric Company (**PG&E**)
13 seeks approval in this proceeding. This testimony focuses on the following issues in
14 Commissioner Baker’s August 3, 2026, Scoping Ruling:¹

- 15 1. Should the California Public Utilities Commission (**Commission**) adopt
16 PG&E’s request to approve 2027 Energy Resource Recovery Account (**ERRA**)
17 Forecast revenue requirements for 2027 ratesetting purposes, as initially
18 forecast in PG&E’s Application and as may be updated through the course of
19 this proceeding and through the Annual Electric True-UP (**AET**) process,
20 including:
- 21 a. Disposition of PG&E’s forecast December 31, 2026, year-end balancing
22 account balances, subject to adjustments for recorded balances through the
23 AET process, and
- 24 b. Disposition of recorded Voluntary Allocation market Option Memorandum
25 Account (**VAMOMA**) balances?
- 26 2. Should the Commission adopt PG&E’s 2027 electric sales forecast?
27 5. Should the Commission approve PG&E’s rate proposals associated with its

¹ See Assigned Commissioner’s Scoping Memo and Ruling, Application (A.) 26-05-007 (Aug. 03, 2026) (**2026 Scoping Ruling**), at 2-4. Internal citations omitted.

1 proposed total electric procurement related revenue requirements, to be
2 effective in rates on January 1, 2027?

3 Based on my review of PG&E's application, supporting workpapers, and responses
4 to discovery, I make the following recommendations to bring PG&E's request in line with
5 prior Commission rules, regulations, resolutions, decisions, and with just and reasonable
6 ratemaking:

- 7 • The Commission should order PG&E to modify its Slice of Day (**SoD**)
8 approach to calculate the retained Resource Adequacy (**RA**) capacity from non-
9 storage resources based on the average of the 24-hour slices in a month,
10 consistent with Southern California Edison Company's (**SCE**) interim
11 approach.
- 12 • The Commission should require PG&E to use Unsold Renewable Portfolio
13 Standard (**RPS**) volumes that have since been retired for RPS compliance
14 purposes prior to the use of pre-2019 banked RECs.
- 15 • The Commission should revisit the structure of the CCA meet-and-confer
16 process in order to improve the accuracy of load forecasts used for ratemaking
17 purposes. The Commission should undertake this effort in the ongoing PCIA
18 Order Instituting Rulemaking (**OIR**).
- 19 • PG&E should implement modifications to its RA accounting practices that
20 reflect all directives from the Commission's Decision (**D.**) 26-07-008 in the RA
21 OIR, and should not reflect only the Commission's directive related to battery
22 foldback.
- 23 • To the extent the Commission approves interim rates in PG&E's 2027 General
24 Rate Case (**GRC**) prior to PG&E's AET filing for 2027 rates, PG&E should

1 include the 2027 Electric Generation revenue requirement with interim rates in
2 its final 2027 PCIA rates.

3 Table RAM-1 provides the impact of the above recommendations on PG&E's
4 proposed PCIA revenue requirement. Adjustment impacts are calculated relative to
5 PG&E's initial filing and the impact will vary after PG&E files its October Update with
6 new market price benchmarks for 2027.

7 **Table RAM-1: Recommended Adjustments to PCIA Revenue Requirement**

Description	Impact (\$ millions)
Slice of Day Non-Storage RA	
Prioritize use of Unsold RPS	
Add 2027 GRC Revenue Requirement	+TBD
RA OIR Modifications	+/-TBD
Total Adjustments	(\$187.7)+TBD

8
9 At the end of my testimony, I provide an update on the status of the final 2026
10 PCIA revenue requirement based on the true-up of forecasted above-market costs with
11 actual above-market costs recorded to date and the market factors driving those changes.
12 This change to the 2026 PCIA revenue requirement manifests in the forecasted year-end
13 PABA balance, which will be updated with additional actual monthly activity in PG&E's
14 October Update.

15 **II. BACKGROUND ON THE PCIA AND PABA**

16 This testimony focuses on PG&E's proposals and other aspects of PG&E's
17 Application that impact the PCIA, including in particular PG&E's approach to valuing the
18 RA associated with non-storage PCIA resources. These issues directly impact CCAs'

1 interests because they either place upward pressure on the PCIA revenue requirement
2 (which, all else equal, increases the PCIA rates customers pay) or contribute to volatility
3 in PCIA rates. In this section of my testimony, I provide background on the PCIA, the
4 calculation of the PCIA revenue requirement, and the allocation of the PCIA revenue
5 requirement to customer vintages because that background provides the context necessary
6 to understand the impact of PG&E’s approach and proposals on customers.

7 **A. Background on the PCIA**

8 CCA customers receive generation services from their local CCA, and receive
9 transmission, distribution, billing, and other services from the incumbent for-profit utility.
10 CCA customers pay CCA-specific generation rates. CCA generation rates vary and are
11 partially influenced by local mandates to procure and maintain clean electricity portfolios
12 that, in many cases, exceed state requirements for renewable generation. In addition, CCA
13 and other unbundled customers are subject to several non-bypassable charges (**NBCs**),
14 including the PCIA and the Cost Allocation Mechanism (**CAM**) surcharge, the 2027 levels of
15 which will be determined in this proceeding.

16 The Commission has an obligation to ensure “indifference,” meaning when
17 customers of IOUs depart from bundled service and receive their electricity from a non-
18 IOU provider, such as a CCA, “those customers remain responsible for costs previously
19 incurred on their behalf by the IOUs — but only those costs.”² The PCIA is the tool the
20 Commission adopted “intend[ing] to equalize cost sharing” between these two groups of
21 customers.³

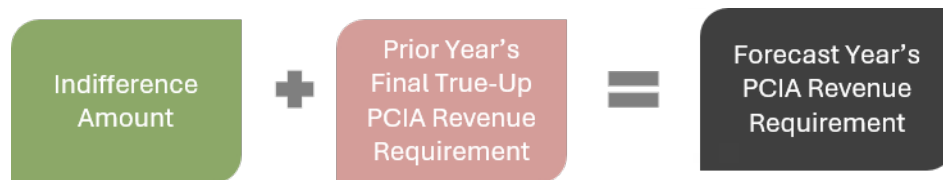
² *Scoping Memo and Ruling of Assigned Commissioner*, R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-029, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 3.

³ *See* D.18-10-019, at 3.

B. Calculation of the PCIA Revenue Requirement

The PCIA revenue requirement is derived from two sources in each utility's ERRA Forecast case, as demonstrated in Figure RAM-1. The first is the Indifference Amount forecasted for the year *for which* rates are being set, *i.e.*, the Indifference Amount forecasted for 2027 in the instant proceeding. The second is the final PCIA revenue requirement for the year *in which* rates are being set, *i.e.*, the final 2026 PCIA revenue requirement in the instant proceeding, which is derived from the balance in the PABA the utility anticipates seeing at the end of the year:

Figure RAM-1



The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio and the forecasted market value of the IOU's supply portfolio as demonstrated in Figure RAM-2:

Figure RAM-2



Total Utility Portfolio Cost includes:

- (i) the cost for Utility-Owned Generation (**UOG**) (*i.e.*, the capital investment recovery and fixed maintenance costs the Commission sets in a GRC),
- (ii) purchased power such as that from power purchase agreements (**PPAs**),

- (iii) fuel costs for UOG and PPAs with tolling agreements, and
- (iv) California Independent System Operator (CAISO) grid charges and revenues, net of any sales.⁴

The forecasted Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (MPBs), an administratively determined set of proxy values that is intended to estimate the market value of the IOU's resource portfolio.⁵ Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and RA Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.⁶
- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.⁷
- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.⁸

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).⁹ Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:¹⁰

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour (\$/MWh). It

⁴ D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011), at 8-9.

⁵ 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 Power Charge Indifference Adjustment for a given year.")

⁶ *Ibid.*

⁷ *Ibid.*

⁸ *Ibid.*

⁹ *Ibid.*

¹⁰ *Ibid.*

is sometimes referred to as “Brown Power Index,” “Brown Power component,” “Brown Power Adder,” or “Brown Power benchmark.”¹¹

- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in \$/MWh.¹²
- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt-month (\$/kW-month).

The forecast utility portfolio value calculation is shown in Figure RAM-3 below:

Figure RAM-3



The forward-looking, forecasted ingredients of total portfolio cost and value are netted to produce the Indifference Amount portion of the PCIA revenue requirement.

The second portion of the PCIA revenue requirement is the “true-up.” The “true-up” modifies the forecasted PCIA revenue requirement from the prior year to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio. The true-up also incorporates the updated proxy market values for products the utilities used to serve bundled customers, changing the *forecast* energy, RPS, and RA MPBs to *final* energy, RPS, and RA MPBs. This true-up relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure RAM-4 below:¹³

¹¹ *Ibid.*, at 7.

¹² *Ibid.*

¹³ Because the true-up for 2026 occurs during 2026, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E’s Application includes an estimate of the 2026 year-end PABA balance comprising a combination of actual

Figure RAM-4

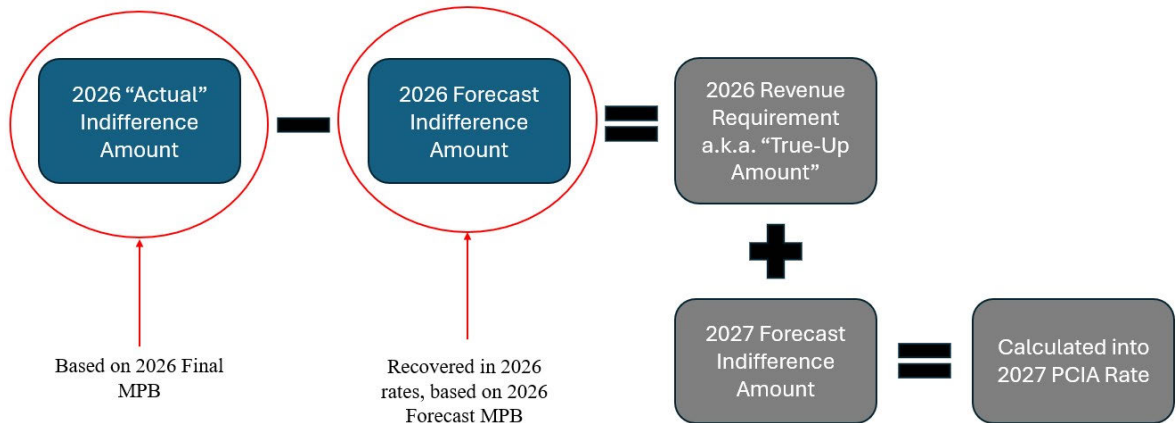


Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact adjustment to the forecasted PCIA revenue requirement for unbundled customers. Decision 18-10-019 approved such an adjustment via the PABA, a rolling balancing account tracking the difference between the forecast costs and revenues used to determine the forecasted PCIA revenue requirement and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.

PG&E calculates this final 2026 portfolio value, uses it as an input to the actual 2026 indifference amount, and finalizes the 2026 True-Up Amount in this case, as shown below in Figure RAM-5.

entries from January through March 2026 and a projection of activity from April through December 2026. PG&E's October Update should include an estimate of the 2026 year-end PABA balance comprising a combination of actual entries from January through August 2026 and a projection of activity from September through December 2026. The final December 31, 2026, advice letter implementing the proceeding will include actual entries.

Figure RAM-5



To summarize, PG&E’s PCIA rates for 2027 will be set in this proceeding based on these two components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E’s PCIA-eligible generation portfolio in 2027 and the forecasted market value of PG&E’s PCIA-eligible generation portfolio in 2027; and (2) the final 2026 PCIA True-Up Amount based on the year-end balance in the PABA. The Indifference Amount and the True-Up Amount are added together to form the 2027 PCIA revenue requirement recovered through rates from bundled and unbundled customers.

C. Customer Vintaging and Allocation

Each generation resource and customer is assigned a “vintage” year. A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned to vintage years according to the date the customer departed bundled IOU service.¹⁴ Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g., vintage 2027 in the current application). Each vintage is assigned both a separate Indifference

¹⁴ Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.

1 Amount and a separate True-Up Amount.¹⁵ Customers are responsible for the cumulative
2 Indifference Amount (and True-Up Amount) for years prior to and including their vintage.
3 The PCIA revenue requirement is allocated among both bundled and unbundled customers
4 based on their vintage¹⁶ and their rate class using the allocation factors from PG&E's most
5 recently approved GRC.¹⁷

6 **III. PG&E SHOULD REFORM ITS SOD METHODOLOGY FOR NON-STORAGE**
7 **RESOURCES**

8 As discussed in Section II of my testimony, a key component in PG&E's
9 calculation of the value of its PCIA-eligible generation resources—which in turn drives the
10 Indifference Amount recovered from bundled and unbundled customers through the
11 PCIA—is the RA value of those resources. PG&E calculates the RA value of its PCIA-
12 eligible portfolio by multiplying the total RA quantity associated with that portfolio (in
13 MWs) by the RA MPB (in \$ per kW-month). The MPB is an administratively set proxy
14 value provided each October for use in that current year.

15 In this proceeding, the RA value of PG&E's PCIA-eligible resources is impacted
16 by certain changes to the Commission's RA program. Those changes include the
17 implementation of a "Slice-of-Day" approach to RA compliance, which I address in this
18 section of my testimony, and also include certain changes directed by D.26-07-008, which
19 I discuss further in Section IV of my testimony.

¹⁵ D.11-12-018, at 9.

¹⁶ *Ibid.*

¹⁷ D.18-10-019, at 122 and Ordering Paragraph (OP) 4.

1 The Commission adopted the Slice-of-Day RA framework through the 2021 RA
2 program rulemaking¹⁸ and it became effective in 2025.¹⁹ The SoD framework considers
3 the capacity contribution of a resource during each hour of the “worst day” of each month
4 in order for each Load-Serving Entity (**LSE**) to demonstrate it can meet its capacity
5 requirements in all hours of that day. The SoD framework was developed in response to
6 issues identified in a 2019 RA program rulemaking.²⁰ Specifically, the rulemaking was
7 intended to address the following:

8 “Examination of the broader RA capacity structure to address energy
9 attributes and hourly capacity requirements, given the increasing
10 penetration of use-limited resources, greater reliance on preferred resources,
11 rolling off of a significant amount of long-term tolling contracts held by
12 utilities, and material increases in energy and capacity prices experienced
13 in California over the past years.”²¹

14 Prior to the Commission’s approval of the SoD framework in D.22-06-050, the
15 Commission required LSEs to demonstrate compliance with the RA program requirements
16 based on the Net Qualifying Capacity (**NQC**) associated with their RA resources—a
17 measure of each resource’s capacity contribution in the single peak hour of each month.
18 The SoD methodology, in contrast, requires LSEs to show sufficient capacity to meet 24
19 separate hourly RA requirements across each month of the year.

20 While D.22-06-050 did not require LSEs to implement the SoD framework for
21 PCIA ratemaking purposes, recent ERRA cases have nevertheless considered interim

¹⁸ D.22-06-050, at 120-122, Findings of Fact 10-21.

¹⁹ D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 6, 2023), at 73.

²⁰ R.19-11-009, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations* (Nov. 7, 2019), at 5.

²¹ D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program* (July 15, 2021), at 25.

1 approaches to SoD implementation until such time as the Commission comprehensively
2 addresses SoD implementation in a rulemaking. As I discuss below, the Commission
3 addressed PG&E's implementation of the SoD framework for energy storage resources in
4 last year's Erra Forecast proceeding, directing PG&E to apply SCE's interim SoD
5 method to calculate the RA value of those resources. It should complete the interim
6 implementation of the SoD framework in this proceeding, and direct PG&E to implement
7 SCE's interim SoD method to calculate the RA value of non-storage resources until such
8 time as the Commission addresses SoD implementation more comprehensively in the
9 PCIA rulemaking. In fact, the Commission just issued a scoping ruling in the PCIA OIR
10 that identified SoD implementation as a Track 4 topic.²²

11 **A. The Commission's Decision in the 2026 Erra Forecast Case Resolved**
12 **the SoD RA Capacity Calculations for Energy Storage Resources Only**

13 PG&E first implemented the SoD framework for the purpose of calculating the
14 PCIA in its 2026 Erra Forecast case.²³ In that case, PG&E proposed to calculate the
15 monthly RA contribution of each resource based on the weighted hourly average of each
16 of the 24 hours in the SoD capacity calculation.²⁴ The weighting was derived from the CEC
17 hourly system load forecast, which resulted in more weight being given to hours with
18 greater demand requirements.²⁵

²² R.25-02-005, *Assigned Commissioner's Second Amended Scoping Memo and Ruling*, at 6. (Aug. 18, 2026).

²³ A.25-05-011, *Application of Pacific Gas and Electric Company for adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (Erra) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*.

²⁴ A.25-05-011, PG&E Opening Testimony, at 5-12 to 5-13.

²⁵ *Ibid.*

1 CalCCA objected to PG&E's RA SoD proposal. PG&E's proposal to average
2 storage RA capacity across all 24 hours, including the hours in which storage is charged,
3 did not accurately value the capacity contribution of storage resources because it resulted
4 in a near-zero RA quantity for storage, among other things.²⁶ CalCCA recommended the
5 Commission address SoD implementation for PCIA ratemaking purposes in a rulemaking,
6 so that the issue could be addressed holistically, including any impacts on both the price
7 and quantity terms used to assess the RA value of PG&E's portfolio.²⁷ CalCCA
8 recommended in the alternative that the Commission adopt SCE's interim SoD
9 methodology, because that methodology produces results that more closely comport with
10 market realities (relative to PG&E's proposal).²⁸ SCE's interim SoD methodology
11 determines RA capacity based upon the NQC of baseload resources, the average of all 24
12 hours of SoD capacity for intermittent resources, and the NQC for storage resources, minus
13 an estimate of the RA capacity needed for charging.²⁹

14 In its rebuttal testimony, PG&E proposed certain changes to its SoD methodology
15 to address CalCCA's observation that its original proposal resulted in an unreasonable
16 near-zero RA value for energy storage resources. PG&E proposed to change its weighting
17 approach to apply a 100 percent weighting to the peak load hour in each month and weight
18 the other 23 hours at zero percent.³⁰ PG&E, however, applied this change to its SoD
19 methodology across all resources (baseload, intermittent, and storage). PG&E's revised

²⁶ A.25-05-011, Direct Testimony of Brian S. Dickman, at 14:4-7.

²⁷ *Ibid.*, at 30:3 - 34:15.

²⁸ *Ibid.*, at 30:3 - 34:15.

²⁹ *Ibid.*, at 30:12-17 and A.26-05-006, *Application of Southern California Edison Company (U 338-E) for Approval of its 2027 ERRA Forecast Proceeding Revenue Requirement*, SCE Energy Resource Recovery Account (ERRA) 2027 Forecast of Operations, at 137:5 – 138:24, included as Attachment RAM-4.

³⁰ A.25-05-011, PG&E Rebuttal Testimony, at 3-5:10-25.

1 SoD proposal did not resolve CalCCA’s concerns, nor did it reflect SCE’s interim SoD
2 methodology for baseload, intermittent, or storage resources.

3 Ultimately, in its Final Decision, the Commission determined it was reasonable for
4 PG&E to implement the SoD framework in the 2026 ERRA Forecast, but also agreed with
5 CalCCA’s position on energy storage.³¹ The Commission found neither of PG&E’s
6 proposed SoD RA methodologies (original or revised) to be reasonable, and instead
7 ordered PG&E to “adopt the SCE SoD methodology on an interim basis while awaiting a
8 more comprehensive decision on the implementation of the SoD methodology.”³²

9 The Commission’s decision in the 2026 ERRA Forecast case was specific to the
10 SoD methodology for energy storage resources. The Commission stated:

11 “PG&E did not provide sufficient evidence that the original and revised
12 proposals would reasonably discount the RA value of *storage resources* by
13 conflating energy with capacity and failing to account for batteries’ ability
14 to provide capacity in any hour.”³³

15
16 “SCE’s methodology is simply a method to discount the NQC of *storage*
17 *resources* to account for the fact that *storage* is not available at its NQC
18 value for 24 hours. PG&E has sufficient information to apply SCE’s current
19 methodology for calculating the RA sales; PG&E would apply SCE’s
20 current methodology for calculating the RA sales, unsold and retained RA
21 volumes *for storage resources*.”³⁴

22 PG&E also understood the Commission’s order to refer only to storage resources.

23 In the Advice Letter³⁵ describing their implementation of the Commission’s order into the
24 2026 PCIA rates, PG&E stated: “Ultimately, in D.25-12-027 the Commission found it was

³¹ D.25-12-027, *Decision Approving Pacific Gas and Electric Company’s 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast* (Dec. 18, 2025), at 37.

³² *Id.*, at 37-38.

³³ *Id.*, at 37 (emphasis added).

³⁴ *Id.*, at 38 (emphasis added).

³⁵ Advice 7820-E, *Notification of PG&E’s Implementation of its Slice-of-Day Methodology in Compliance with Decision 25-12-027* (Jan. 22, 2026).

1 reasonable for PG&E to adopt Southern California Edison’s (“SCE’s”) interim SoD
2 methodology for storage resources only on an interim basis.”³⁶ PG&E further
3 acknowledged that its SoD implementation for the remaining non-storage resource
4 reflected the prior NQC approach when it stated “For all non-storage resources, the NQC
5 values were based on currently approved NQC counting rules.”³⁷

6 Nothing in D.25-12-027 addresses or approves PG&E’s approach to SoD
7 implementation for the purposes of the valuation of RA capacity from **non-storage**
8 **resources**. The Commission has not yet addressed the implementation of the SoD
9 framework for PG&E’s non-storage resources, nor has it yet comprehensively addressed
10 SoD implementation for PCIA ratemaking purposes in a rulemaking. Therefore, it is
11 appropriate for the Commission to resolve the implementation of SoD for PG&E’s non-
12 storage resources in this case. The Commission should ensure PG&E implements SCE’s
13 interim SoD methodology in its entirety, rather than the piecemeal approach PG&E has
14 currently taken.

15 **B. PG&E’s RA Valuation Methodology for Non-Storage Intermittent**
16 **Resources Does Not Reflect SCE’s Interim SoD Methodology for Non-**
17 **Storage Intermittent Resources**
18

19 PG&E’s proposed RA valuation methodology uses each generation resource’s
20 output in the single peak hour per month to determine that resource’s capacity contribution
21 and the quantity used to value Retained RA in the PCIA—whether that resource is
22 baseload, intermittent, or storage.³⁸ As I mentioned above, PG&E’s RA valuation
23 methodology is markedly different from SCE’s interim SoD methodology. Specifically,

³⁶ *Ibid.*, at 1.

³⁷ *Ibid.*, at 1.

³⁸ PG&E’s Public Testimony, at 5-12:3-13.

while PG&E's RA valuation methodology reflects SCE's interim SoD methodology *for storage resources*, it does not reflect SCE's interim SoD methodology for *non-storage resources*. The table below compares PG&E's RA valuation methodology for each resource type to SCE's interim SoD methodology.

Table RAM-2: Comparison of SoD Methodologies for PG&E and SCE

Resource Type	SCE	PG&E
Baseload ³⁹	NQC	NQC
Energy Storage	NQC – NQC * 4 / 24 / Round Trip Efficiency	NQC – NQC * 4 / 24 / Round Trip Efficiency
Intermittent (Wind/Solar)	24-hr average	Peak hour

As the table above demonstrates, PG&E's methodology matches SCE's interim SoD method for energy storage resources, consistent with D.25-12-027. But PG&E's methodology *does not* match SCE's methodology for intermittent resources.

This leads to a needlessly inconsistent outcome. Under the status quo,⁴⁰ the exact same wind and solar resources would receive different valuations of retained RA capacity depending on whether they were procured by PG&E or SCE. Those different retained RA valuations would each be multiplied by the same statewide RA MPB value, resulting in different retained RA values. SCE and PG&E customers receiving a different retained RA valuation for the same resources solely because they are customers of a different utility would clearly be an inequitable outcome.

This situation can be easily remedied by clearly extending the requirement that PG&E adopt SCE's interim SoD methodology to all resources in its portfolio. The 2027 Forecast proceeding provides an opportunity for PG&E to complete its implementation of

³⁹ Mathematically, the retained RA value for baseload resources is the NQC under any averaging methodology of the 24-hour slices because baseload resources are provided the same capacity amount in each hour, at their NQC, under the Commission's approved SoD methodology.

⁴⁰ A.26-05-006, SCE Opening Testimony, at 137-139, included as Attachment RAM-4.

SCE’s interim method. The Commission should order PG&E to align its interim SoD framework in the PCIA with SCE’s method across all resource types. To fully align PG&E and SCE’s SoD calculations, PG&E should determine the RA contribution of a non-storage intermittent resource by averaging its capacity contribution equally across all 24 hours in the worst day (i.e. day that contains the hour with the highest coincident peak load forecast). This approach is nearly identical to the one PG&E originally proposed in its initial filing in the 2026 ERRA Forecast case.⁴¹ Making that change would result in the following changes in capacity contribution by resource type:

Table RAM-3: Retained RA Capacity Change Under Proposed SoD Modifications

Capacity (MW)	PG&E SoD Methodology	CalCCA Proposed SoD Methodology	Change
Biomass	92	92	0
Digester Gas	2	2	0
Geothermal	18	18	0
Landfill Gas	22	22	0
Hydro	2,479	2,479	0
Fossil	1,703	1,703	0
Solar PV	526	911	385
Solar Thermal	144	177	33
Wind	191	167	(24)
Total	5,177	5,571	394

C. Whereas SCE’s Interim SoD Methodology Reflects the Evolution of the RA Program, PG&E’s Approach Undercuts It

Again, PG&E’s RA valuation methodology uses each resource’s output in the single peak hour per month to determine that resource’s capacity contribution and the quantity used to value Retained RA in the PCIA. This approach is nearly identical to the

⁴¹ The only difference is the weighting of the hours. PG&E originally proposed in its 2026 ERRA forecast case to weight the hours by load ratio share, while SCE’s methodology provides equal weight to all the hours.

1 NQC-based approach that the SoD framework replaced. That NQC-based approach
2 measured capacity in the single peak hour of each month. As such, PG&E's current RA
3 valuation methodology does not implement the SoD framework, it undercuts it. PG&E has
4 in effect circumvented the Commission's effort to evolve the RA program towards
5 considering all hours in the day to ensure resource adequacy. Aligning PG&E's
6 methodology with SCE's would provide consistency across SoD implementation and
7 would continue the RA program's evolution beyond focusing on the single hour of a month.

8 While PG&E may claim its RA valuation methodology is superior to SCE's interim
9 SoD method because it is consistent across resource types, that argument has no merit.
10 There is no reason PG&E should apply the same RA valuation methodology across
11 resources with markedly different characteristics. The objective of the RA capacity
12 determination is to provide as accurate a measure as possible of each resource's capacity
13 contribution to PG&E's resource adequacy requirement, and ultimately, to accurately
14 reflect resource value.

15 Energy storage is a fundamentally different resource type than other electric
16 generators in that its primary objective is to move capacity in time. It does not generate
17 electricity from alternate sources (such as the wind, sun, or natural gas), it stores electricity
18 generated from other sources in order to dispatch that energy at the optimal time. As such,
19 it is reasonable that accurately measuring the capacity contribution of energy storage would
20 require a different approach than for non-energy storage resources.

21 **D. PG&E's Own Experience with RA Transactions Support A Higher**
22 **Valuation for Solar Resources**

23 PG&E's approach to valuing RA from solar resources produces an RA capacity
24 amount that is approximately 12 percent to 21 percent of the resource's nameplate capacity,

1 depending on resource-specific characteristics. The comparable RA capacity amount for
2 PG&E's baseload plants is 88 percent to 100 percent of nameplate. Therefore, for every
3 unit of nameplate capacity baseload resources provide about five to seven times as much
4 RA capacity as solar resources. PG&E's approach suggests that RA capacity transactions
5 for baseload resources command a five to seven times premium as compared to solar in the
6 market (because the price term—the RA MPB—is fixed across resource types). SCE's
7 interim SoD RA methodology (which CalCCA recommends PG&E apply to all non-
8 storage resources), in contrast, would not change the amount of RA capacity as a share of
9 nameplate for baseload resources, but it would result in RA capacity for solar resources
10 that is about 24 percent to 27 percent of nameplate capacity.

11 I reviewed the RA transaction data PG&E provided to assess whether the premium
12 suggested by PG&E's RA valuation approach is indicated in that data.⁴² PG&E provided
13 all transactions in which it sold RA to other parties for delivery in calendar year 2026. That
14 dataset shows that the weighted average price for solar capacity was [REDACTED] while
15 the weighted average price for baseload capacity was [REDACTED]. Based on PG&E's
16 own experience, baseload capacity prices command only about a [REDACTED] to
17 solar capacity prices, not the five to seven times premium that PG&E's RA valuation
18 method would suggest. I note the data set provided by PG&E does not capture all RA
19 market transactions; other transactions are not available to PG&E nor other parties in this
20 case. But even with the limitations in the available data, that data would suggest that SCE's
21 RA valuation approach for non-storage resources is more reasonable than PG&E's

⁴² PG&E's response to DR CalCCA 006-Q004, Attachment, included in Attachment RAM-3.

1 approach, because the former produces a baseload premium relative to solar resources that
2 more closely reflects the market transaction data PG&E provided.

3 **IV. TO THE EXTENT PG&E REVISES ITS RA VALUATION METHODOLOGY IN**
4 **RESPONSE TO D.26-07-008, IT SHOULD COMPREHENSIVELY REFLECT**
5 **ALL ASPECTS OF THAT DECISION**

6 PG&E filed Supplemental Testimony on July 29, 2026, to address load forecasting
7 and its RA valuation methodology. PG&E did not propose quantitative changes to the
8 PCIA forecast in its Supplemental Testimony. Rather, it previewed methodological
9 changes it plans to implement in time for its Fall Update filing. In this section of my
10 testimony, I will address PG&E’s proposed methodological changes related to its RA value
11 calculations and why PG&E should reflect D.26-07-008 with any RA valuation
12 methodology revisions.

13 PG&E’s proposed methodological changes to its RA value calculations stem from
14 a Commission decision in the RA rulemaking (D.26-07-008, or “RA OIR Decision”)⁴³
15 which is intended to better align RA capacity calculations with the operational experience
16 of certain resources. Specifically, the Commission instituted reforms for energy storage
17 resources, energy-only resources, and long-duration storage resources.⁴⁴

18 The energy storage reforms proposed to modify the capacity attributable to a battery
19 by accounting for the effect of “foldback” in which a battery system can limit its output
20 when reaching pre-defined state of charge thresholds to reduce or eliminate instances of
21 deep discharge and maintain battery health. This effect can reduce the continuous capacity
22 a battery can deliver over its full discharge duration. In order to capture the effects of

⁴³ R.25-10-003, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations* (Oct. 9, 2026).

⁴⁴ PG&E Supplemental Testimony, at 7:6-9.

foldback, the Commission modified the calculation of Maximum Continuous Energy (MCE) in its Master Resource Database (MRD).⁴⁵

PG&E proposes to change its calculation of battery energy storage retained RA to also account for the effect of foldback and reflect the Commission's RA OIR Decision. PG&E proposes to replace the NQC variable in its energy storage retained RA formula with an "MCE / 4" variable.⁴⁶ The currently approved formula for calculating the retained RA from energy storage is as follows⁴⁷

$$\text{Retained RA} = \text{NQC} - \left(\frac{\text{NQC} \times 4}{24 \times \text{RTE}} \right)$$

where RTE refers to the round-trip efficiency of each battery. PG&E's proposed revisions would result in the retained RA from energy storage calculated as follows⁴⁸

$$\text{Retained RA} = \frac{\text{MCE}}{4} - \left(\frac{\text{MCE}}{24 \times \text{RTE}} \right)$$

CalCCA does not object in concept to PG&E's proposed modification. It is reasonable for PG&E to use the most accurate and up to date information in calculating the retained RA attributable to battery energy storage systems. However, as PG&E has not yet applied this new methodology to its calculation of RA value, the details of that application in the Fall Update will require review. Additionally, PG&E's proposal raises two concerns.

First, PG&E's proposal, if adopted, could increase the disparities between PG&E's RA value calculations and the calculations implemented by the other investor-owned utilities (IOUs). PG&E is the only IOU to have filed supplemental testimony prospectively

⁴⁵ *Id.*, at 7:23-31.

⁴⁶ The "/ 4" is necessary as MCE is a cumulative amount of discharge over a 4-hr discharge period while NQC is the capacity output of a battery in a single hour.

⁴⁷ PG&E Supplemental Testimony, at 6.

⁴⁸ *Id.*, at 9:16.

1 identifying a proposed change to its RA value calculation based on the RA OIR Decision.
2 This is further evidence that methodological changes in RA calculations are best left for
3 rulemakings, consistent with CalCCA's prior advocacy.

4 The second concern is that PG&E's proposal in its Supplemental Testimony makes
5 no mention of any prospective changes in its SoD RA methodology to address the other
6 two elements of the RA OIR Decision: energy-only resources and long-duration energy
7 storage.

8 The Commission's RA decision made modifications to allow excess energy from
9 co-located energy-only resources to count towards charging sufficiency requirements.⁴⁹
10 This acknowledges the reality that while energy-only resources co-located with energy
11 storage might not have any RA capacity value themselves, they reduce the need for the
12 energy storage systems to utilize RA capacity from other resources and so therefore should
13 receive less of a RA capacity reduction associated with charging. PG&E has at least one
14 applicable co-located energy-only resource.⁵⁰

15 The Commission's RA decision also modified the RA calculations and charging
16 sufficiency requirements to account for the operational characteristics of long-duration
17 energy storage resources. PG&E's Supplemental Testimony did not specifically propose
18 any changes to its SoD RA methodology to account for the Commission's changes to long-
19 duration energy storage, and PG&E currently does not have any resources that would
20 qualify as long-duration energy storage.⁵¹

⁴⁹ *Id.*, at 8:1-9.

⁵⁰ PG&E's Response to DR CalCCA 006-Q009, included in Attachment RAM-3.

⁵¹ PG&E's Response to DR CalCCA 009-Q007.

1 To the extent PG&E implements any modifications to its RA value calculation
2 methodology in response to the Commission's RA OIR Decision, it should
3 comprehensively account for all aspects of that Decision, not selectively implement certain
4 elements of the Decision. CalCCA reserves its right to comment further on PG&E's
5 proposed modifications to its RA valuation methodology after reviewing PG&E's
6 implementation of those modifications in the Fall Update.

7 **V. PG&E SHOULD PRIORITIZE THE USE OF UNSOLD RPS THAT IS NOW POST-**
8 **2018 BANKED RECS AHEAD OF PRE-2019 BANKED RECS.**

9 In addition to RA value, a second major component of the value of PG&E's overall
10 PCIA portfolio is its RPS value. PG&E's RPS accounting, and in particular, its
11 categorization of RPS as Retained, Sold or Unsold, can have a significant impact on the
12 Indifference Amount and consequently on PCIA rates.

13 PG&E's compliance with its "Minimum Retained RPS" requirement directly
14 impacts the RPS value of its PCIA-eligible portfolio. Under the Minimum Retained RPS
15 requirement, adopted in D.20-02-047, in the event PG&E's bundled net RPS position is
16 forecasted to fall below its bundled RPS target for the applicable ERRA year, PG&E must
17 incorporate an incremental Renewable Energy Credit (**REC**) volume to make up the
18 shortfall.⁵² In this year's Application, similar to several prior years, PG&E forecasts a
19 shortfall towards its 2027 Minimum Retained RPS requirement.⁵³ And, as in prior years,
20 PG&E intends to use banked RECs to cover its shortfall and meet the Minimum Retained
21 RPS requirement.⁵⁴ "Banked" RECs are RECs PG&E generated in prior years, in surplus
22 of PG&E's RPS requirements.

⁵² PG&E Public Testimony, at 5-12.

⁵³ *Id.*, at 8-17.

⁵⁴ *Id.*, at 8-17 to 8-18; Table 8-4.

1 In general, PG&E has prioritized the use of RECs banked after 2018 (“post-2018
2 banked RECs”) over RECs banked before 2019 (“pre-2019 banked RECs”). [REDACTED]

3 [REDACTED]
4 [REDACTED] PG&E prioritizes banked RECs in this manner because the appropriate
5 valuation of pre-2019 banked RECs has been, and continues to be, the subject of dispute
6 between various parties; whereas parties have generally agreed on the appropriate valuation
7 of post-2018 banked RECs. Notably, in PG&E’s 2024 ERRR Forecast case, in which
8 PG&E’s use and valuation of banked RECs was a disputed issue, the Commission directed
9 PG&E to prioritize the use of post-2018 Banked RECs ahead of pre-2019 Banked RECs,
10 as a result of the ongoing dispute over the valuation of pre-2019 Banked RECs.⁵⁵ That
11 dispute remains active in Track 2 of the PCIA OIR. At the time of submitting this testimony
12 that dispute has not yet been resolved through a non-appealable final Commission order.
13 As such, PG&E should continue to prioritize the use of post-2018 banked RECs towards
14 its Minimum Retained RPS requirement, ahead of pre-2019 banked RECs.

15 In this case, while PG&E asserts it [REDACTED]⁵⁶
16 PG&E has a significant volume of Unsold RPS available from 2023 and 2024.⁵⁷ As I will
17 explain below, a portion of those Unsold RPS volumes should be considered post-2018
18 banked RECs and therefore should be used towards PG&E’s 2027 Minimum Retained RPS
19 requirement (ahead of any pre-2019 banked RECs).

20 Specifically, PG&E has a balance of 3,073,161 MWh of 2023 vintage Unsold RPS,
21 and 412,848 MWh of 2024 vintage Unsold RPS.⁵⁸ Unsold RPS represents renewable

⁵⁵ D.23-12-022, at 17 and Conclusion of Law 5.

⁵⁶ PG&E Public Testimony, at 8-18, Table 8-4.

⁵⁷ *Id.*, at 8-15, Table 8-2.

⁵⁸ *Id.*

1 energy that was generated in the vintage year but not used for RPS compliance in that year
2 (or in subsequent years) nor sold to a third party. While the RECs associated with that
3 renewable energy generation remain active in WREGIS, they could, in theory, be sold to
4 another counterparty in need of RECs for their own compliance requirement, hence PG&E
5 categorizes those RECs as “Unsold RPS.” However, RECs remain active (or un-retired) in
6 WREGIS only for a period of three years from their generation. After that time, they must
7 be retired, which means they can no longer be sold. After the RECs are retired, they are
8 still eligible to meet California’s RPS standard under PUC rules. RECs that have been
9 retired in WREGIS but are still eligible to be used for RPS compliance are known as
10 “Banked RECs.” PG&E has retired in WREGIS 3,135,126 RECs in 2023 vintage Unsold
11 RPS as of August 6th, 2026.⁵⁹ These 3.1 million RECs should therefore be considered post-
12 2018 Banked RECs, and should be prioritized for use in meeting PG&E’s 2026 and 2027
13 RPS compliance ahead of pre-2019 banked RECs. In its testimony, PG&E forecasts a
14 [REDACTED] in meeting its 2026 RPS compliance target.⁶⁰ As a result,
15 PG&E proposes [REDACTED]
16 [REDACTED]⁶¹ PG&E also forecasts a [REDACTED]
17 [REDACTED] in meeting its 2027 RPS compliance target.⁶² PG&E proposes [REDACTED]
18 [REDACTED].⁶³

19 However, in light of the fact that 3,135,126 RECs from PG&E’s 2023 vintage
20 Unsold RPS are now properly considered “Banked RECs”, PG&E should prioritize its use

⁵⁹ PG&E’s response to DR CalCCA 007-004, included in Attachment RAM-3.

⁶⁰ PG&E Confidential Testimony, at 8-19, Table 8-5.

⁶¹ PG&E workpaper 08. ERRAs_2027_Forecast_WP_PGE_20260515_Tables_8-2_8-3_8-4_CONF at worksheet “Applied_Historical”, rows 6 and 11.

⁶² PG&E Confidential Opening Testimony, at 8-15, Table 8-2, line number 15.

⁶³ *Id.*, at 8-18, Table 8-4, line number 1.

of those volumes to meet its 2026 and 2027 shortfalls, consistent with its current practice of prioritizing post-2018 banked RECs, and consistent with the Commission-directed approach to prioritization while a dispute over the valuation of pre-2019 banked RECs remains pending. The table below shows how PG&E should apply its post-2018 banked RECs towards its 2026 and 2027 shortfalls.

Table RAM-4: Retained RA Capacity Change Under Proposed SoD Modifications

Delivery Year	Vintage Credited	Pre-2026 Adjusted Net RPS Position	Minimum 2026 Entry	Minimum 2027 Entry	Post-2027 Adjusted Net RPS Position
2013		1,928,480			1,928,480
2014		3,980,017			3,980,017
2015		4,482,478			4,482,478
2016		5,379,425			5,379,425
2017		3,704,274			3,704,274
2018		385,883			385,883
2019					
2020	2026				
2021					
2022					
2023	2026, 2027	3,135,126 ⁶⁴			
2024					
2025					

PG&E's prioritization of post-2018 Banked RECs to meet its 2026 and 2027 shortfalls will result in an increase in the retained RPS value of [REDACTED] at the current RPS MPB.

⁶⁴ PG&E's response to DR CalCCA 007-Q004b indicates PG&E has retired 3,135,126 of unsold RPS RECs from 2023, out of a total reported 3,408,173 in Unsold RPS RECs. Table 8-2 in PG&E's Direct Testimony shows a balance of 3,073,161 in 2023 Unsold RPS. The cause of this discrepancy is not clear.

1 **VI. PG&E'S APPROACH TO DATA CENTER LOAD FORECASTING RISKS**
2 **INTRODUCING SIGNIFICANT RATE VOLATILITY INTO THE PCIA**

3 PG&E has taken three steps in its 2027 ERRR Forecast to account for the unique
4 challenges and risks posed by data center load and load growth. PG&E has (1) removed
5 historical data center sales from its forecast so its regression models for its sales forecast
6 do not include trends for large data centers;⁶⁵ (2) has separately forecasted future data
7 center load based on the specific data centers it expects to come online;⁶⁶ and (3) has
8 proposed to refresh that forecast in the October update with the most recent assumptions
9 and data available.⁶⁷

10 While the steps taken by PG&E to improve its data center forecast are laudable,
11 shortcomings remain which risk introducing significant rate volatility into the PCIA. Those
12 risks are likely concentrated into specific PCIA vintage rates paid by CCA customers rather
13 than the PCIA vintage rates paid by bundled customers.

14 Data centers bring a host of risks and challenges that are unique from other new
15 loads that are regularly added to the utility system, such as electric vehicles and new
16 residential/commercial development. Those unique risks are the result of the size and scale
17 of proposed new data center loads. Large legacy data centers are typically less than 100
18 MW per site. New enterprise-level data centers being proposed around the country are an
19 order of magnitude larger. For example, a hypothetical single 500 MW new data center
20 operating at 90 percent load factor taking service in PG&E's service territory would
21 increase overall bundled and departed sales by approximately 5 percent.

⁶⁵ PG&E Opening Testimony, at 2-4:21-26.

⁶⁶ *Id.*, at 2-11:4 to 2-13:9.

⁶⁷ PG&E Supplemental Testimony, at 3:5 – 4-15.

One of those challenges created by the scale of new data center load, coupled with uncertainty in the timing of when that load will come online, is the potential for large swings between forecast sales and actual sales. Significant changes between forecast sales and actual sales will result in large changes to PCIA rates over time. While actual PCIA costs eventually will be collected and true-up to the forecast, year-to-year PCIA rate volatility is a concern for customers and CCAs, who have limited insight into and ability to control PCIA rate swings.⁶⁸

The risks of PCIA rate volatility are also not distributed evenly across PG&E's bundled customers and CCA customers. Take the hypothetical example of a single 500 MW data center customer forecasted to come online January 1, 2027 and to operate for the full year at 90 percent load factor which, for one reason or another, has its start of service delayed at least one year. In that instance, all else equal, there would be a significant (~5 percent) decrease between forecast and actual sales which would increase the PCIA between forecast and true-up. Table RAM-5 shows an example of a single data center added to the total sales forecast that is not included in actual sales for that year.

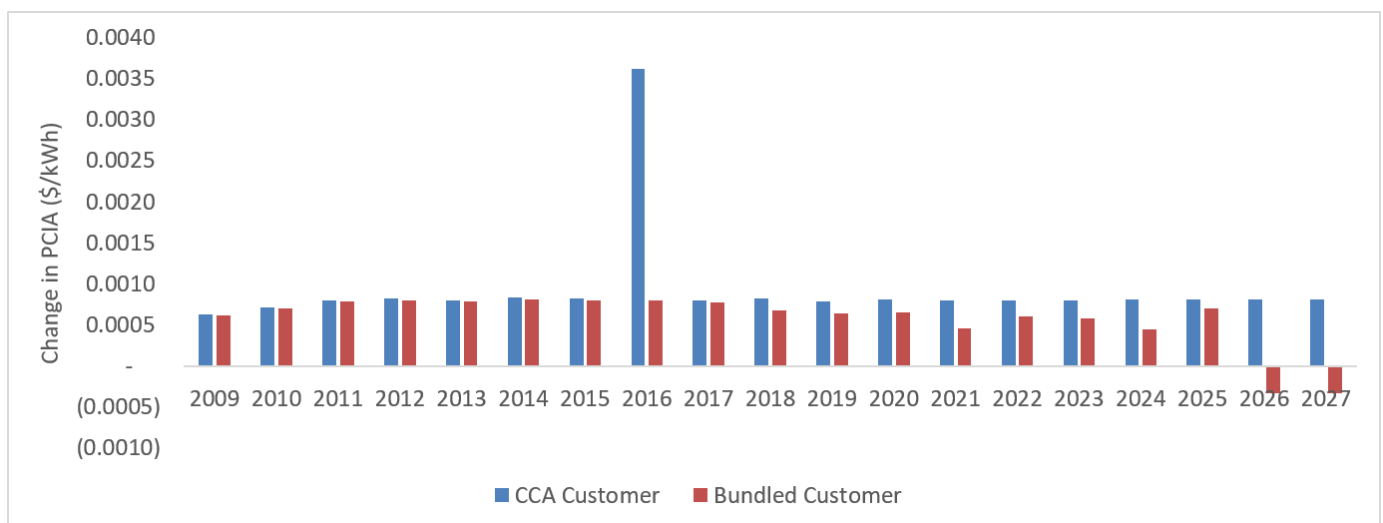
Table RAM-5: Hypothetical 500 MW Data Center Sales Forecast Error

(GWh)	Forecast	Actual	Difference
Total Sales	75	75	0
One 500 MW / 90% LF Data Center	4	0	(4)
Total Load	79	75	(4)

⁶⁸ PCIA rate volatility from data center loads is a concern to the extent data centers are not exempt from the PCIA. It is current practice to include data centers into the applicable vintage of the CCA who they take service from or into the most recent vintage in the case of bundled customers (PG&E response to DR CalCCA 008-Q004, included in Attachment RAM-3). CalCCA takes no position on the issue of data center exemption from the PCIA in this proceeding, and expects that to be an issue discussed in the ongoing PCIA rulemaking.

Should that hypothetical data center customer have been forecast to be a PG&E bundled customer, that change would increase the PCIA for all vintages by approximately \$0.001/ kilowatt-hour (kWh). However, if that hypothetical data center customer were forecast to be a CCA customer, then that change would increase the PCIA for that CCA's specific vintage by approximately \$0.004/kWh and for all other vintages approximately \$0.001/kWh. Figure RAM-6 shows the change to each PCIA vintage if that hypothetical data center customer were a bundled customer or served by a CCA (assumed to be in the 2016 vintage).

Figure RAM-6: PCIA Change from Hypothetical Data Center Customer Sales Not as Forecasted



The risks to PCIA volatility are also present in the form of aggregate overestimation of all data center loads. A collection of assumptions and reliance solely on data center customer-supplied load forecasts results in the risk that PG&E's data center load forecast is inflated. PG&E:

- uses the projected energization date supplied by the customer, without any adjustment for historical experience;⁶⁹
- does not use input from the CCA that might serve the prospective data center, nor from the municipality or authority having jurisdiction for the area in which the data center will be located;⁷⁰
- does not have monthly ramping schedules for new data center loads;⁷¹
- does not include any assumptions about the use of on-site generation, even when it is aware of customers who plan to install such generation;⁷²
- applies an assumed 90 percent materialization rate to each project's ramp schedule, without any adjustment for historical experience;⁷³
- applies an assumed 85 percent capacity utilization rate to the capacity forecast, without any adjustment for historical experience;⁷⁴
- applies an assumed 88 percent load factor, without any adjustment for historical experience.⁷⁵

The collection of these assumptions risks over-forecasting data center load, as each assumption provides an optimistic view of when and how quickly the data center load forecast will be realized. The risk to each of these assumptions is that load will appear less quickly or to a smaller magnitude than forecasted.

⁶⁹ PG&E's Response to DR CalCCA 008-Q009b, included in Attachment RAM-3.

⁷⁰ PG&E's Response to DR CalCCA 008-Q009b and c, included in Attachment RAM-3.

⁷¹ PG&E's Response to DR CalCCA 008-Q010c, included in Attachment RAM-3.

⁷² PG&E's Response to DR CalCCA 008-Q016, included in Attachment RAM-3.

⁷³ PG&E's Response to DR CalCCA 008-Q017, included in Attachment RAM-3.

⁷⁴ PG&E's Response to DR CalCCA 008-Q018, included in Attachment RAM-3.

⁷⁵ PG&E's Response to DR CalCCA 008-Q019, included in Attachment RAM-3.

1 It is difficult to determine the specific risk of PCIA volatility from an inflated data
2 center load forecast in the 2027 PCIA rates because PG&E did not readily provide the data
3 center forecast, citing customer privacy. PG&E has indicated in supplemental testimony
4 that it is revamping its data center forecast for the Fall Update and will make that forecast
5 available to parties. However, PG&E has also stated that specific inputs to that forecast,
6 which will be based on actual customer experience, will remain confidential even as the
7 forecast is public.⁷⁶ If that remains the case, it will continue to be difficult to determine the
8 specific risks from data centers embedded in the PCIA forecast.

9 One approach to improving the accuracy of PG&E's data center load forecast is to
10 improve the process PG&E uses to arrive at that forecast. The current process PG&E uses
11 to forecast data center load is opaque and is not structured to leverage all of the information
12 available to provide the most accurate forecast possible. The current process requires
13 PG&E to meet and confer with CCAs regarding their overall load forecast, including data
14 center load.⁷⁷ But it provides no pathway to resolve differences in forecast load. When
15 PG&E and a CCA are not able to agree on the data center load forecast, then PG&E has
16 stated that it plans to use its own forecast.⁷⁸ This potential outcome is particularly
17 problematic given that PG&E has affirmatively stated that the presumption is that new data
18 centers located in CCA service territory will be served by that CCA.⁷⁹ It stands to reason
19 that the CCA's forecast of that load, and not PG&E's forecast, should be used in
20 determining PCIA and ERRRA rates, particularly because CCAs have unique insight into

⁷⁶ PG&E's Response to DR CalCCA 008-Q014, included in Attachment RAM-3.

⁷⁷ D.16-12-038, at 22, paragraph 3 required PG&E and CCAs to exchange respective load forecasts, starting with the 2018 forecast cycle.

⁷⁸ PG&E's Response to DR CALCCA 008-Q20, included in Attachment RAM-3.

⁷⁹ PG&E Public Testimony, at 2-12.

1 the certainty and timing of data center loads through the local permitting, zoning, and land
2 use requirements in the municipalities comprising the CCAs.

3 The current load forecasting meet and confer process, however, does not require
4 PG&E to use CCAs' load forecasts; does not require PG&E to defend its position prior to
5 using its forecast in an ERRA forecast filing; does not require PG&E to share relevant
6 information regarding its load forecast with CCAs; and does not contemplate a process to
7 resolve differences between PG&E and CCAs.

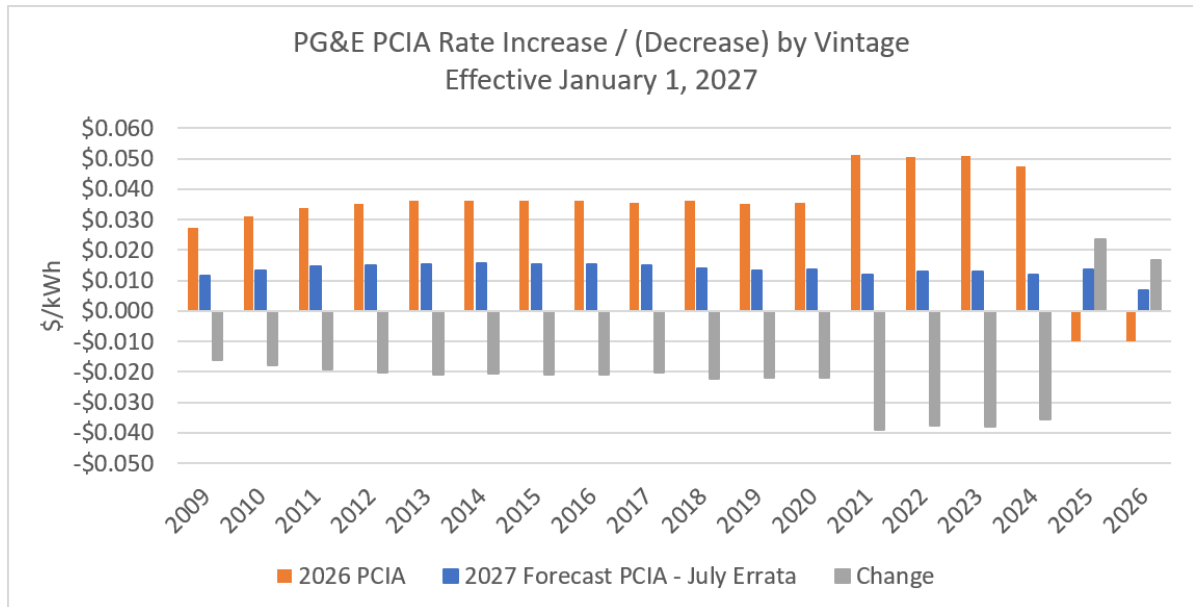
8 In light of the significant implications of data center load on PCIA rate volatility,
9 the rapid growth of data centers in PG&E's service territory, and the outdated structure of
10 the meet-and-confer process, PG&E's data center load forecasting process requires urgent
11 reform. As a part of that reform process, the Commission should treat CCA data center
12 load forecasts as a rebuttable presumption. To the extent PG&E possesses additional
13 relevant information based on discussions with prospective customers or any other source,
14 PG&E should be required to rebut the CCA forecast based on that information
15 (confidentially, if necessary) to prove the accuracy of its conflicting data center load
16 forecast. The Commission should evaluate and adopt reforms to the data center load
17 forecasting process in Track 3 of the PCIA OIR currently underway, because although this
18 issue is particularly acute and urgent in PG&E's territory at the moment, it will likely
19 impact SCE and San Diego Gas & Electric Company's service territories over time.

20 **VII. THE COMMISSION SHOULD AUTHORIZE PG&E TO INCORPORATE ANY**
21 **AUTHORIZED INTERIM 2027 GENERAL RATE CASE REVENUE**
22 **REQUIREMENT INCREASE INTO 2027 PCIA RATES**

23 The 2027 forecasted PCIA rates provided by PG&E in its initial and errata filing
24 show a marked decrease from the 2026 PCIA rates in effect today. For vintages between
25 2009 and 2024 the PCIA rate decreased between \$0.02 and \$0.04 per kWh from its 2026

value. Figure RAM-7 shows the 2027 PCIA forecast from the July errata filing compared to the 2026 PCIA rates in effect today.

Figure RAM-7: 2026 Actual and 2027 Forecast PCIA Rate Comparison by Vintage



This 2027 PCIA is a forecast as of May 2026 and will change through the course of 2026 as actual PCIA revenue is trued up through the PABA and the estimates for 2027 expenses and value to be recovered through the PCIA continue to be refined. One of the factors that will impact the PCIA in the future is a final decision in PG&E's 2027 General Rate Case.

PG&E filed a General Rate Case in May 2025⁸⁰ in order to update its base rates effective for the 2027-2030 time period, starting January 1, 2027. PG&E's forecasted revenue requirement showed a significant \$300 million increase in Electric Generation Revenue Requirement attributable to UOG as compared to 2026.⁸¹ That proposed increase

⁸⁰ A.25-05-009.

⁸¹ PG&E's Errata to Prepared Testimony, at 12-19:29 – 12:20:9.

1 has not yet been included in PG&E's 2027 PCIA forecast.⁸² Adding \$300 million in UOG
2 revenue requirement to the indifference calculation, all else equal, will increase the PCIA
3 by approximately \$0.004 per kWh across all vintages. The current timeline of the GRC
4 estimates a proposed decision in May 2027,⁸³ far too late to include the updated revenue
5 requirement in 2027 PCIA rates. As the Commission has approved PG&E's motion to
6 allow final rates to be effective January 1, 2027, and receive balancing account treatment
7 from that date, delays in implementing the revenue increase risk compounding PCIA rate
8 impacts in 2028.

9 PG&E has filed a motion in the GRC to implement Interim Rates effective January
10 1, 2027, at either 55 percent, 75 percent, or 85 percent of its initial requested revenue
11 requirement increase.⁸⁴ The Commission has not yet ruled on that motion. PG&E indicated
12 in response to a data request that it would plan to include any interim rate relief granted by
13 the Commission in the GRC as an additional revenue requirement for the PCIA
14 calculations.⁸⁵

15 While I take no position on the exact amount of interim rate relief PG&E should be
16 provided, I support the concept of implementing interim rates and rolling that increase into
17 the PCIA, and the Commission should authorize PG&E to incorporate any interim rate
18 relief into 2027 PCIA rates. This remedy would allow for some portion of the proposed
19 Electric Generation revenue requirement increase to be collected through the PCIA in

⁸² PG&E's Prepared Testimony, at 1-5:9-20.

⁸³ PG&E's Response to DR CalCCA 001-Q003, included in Attachment RAM-3.

⁸⁴ A.25-05-009, *Motion of Pacific Gas and Electric Companies (U 39 M) for Interim Rate Recovery* (May 15, 2025).

⁸⁵ PG&E's Response to DR CalCCA 001-Q003, included in Attachment RAM-3.

2027. While this would increase upward pressure on 2027 PCIA rates, it avoids the risk of compounding rate increases in 2028 leading to sharper cost increases for all customers.

VIII. PCIA CALCULATION ERRORS IDENTIFIED BY CALCCA

In its review of PG&E’s initial application, CalCCA identified a number of errors in PG&E’s testimony and workpapers. Those errors were confirmed by PG&E through data request responses and ultimately corrected by PG&E in its errata filing submitted July 17, 2026. PG&E expeditiously provides its ERRA filing workpapers and the master data request response and CalCCA promptly conducts discovery and communicates any errors found. This process underscores the importance of the procedural collaboration between PG&E and CalCCA, to help produce more accurate ERRA and PCIA forecasted rates.

Fossil Unit Vintaging – PG&E inadvertently moved its fossil UOG resources from the 2009 vintage to the Legacy vintage in its initial filing.⁸⁶ Subsequent to CalCCA’s inquiry into the basis for that change, PG&E identified that the movement was in error and ensured the fossil units were reflected in the 2009 vintage in its errata filing.⁸⁷ That error did not have an impact on the PCIA rates as the Legacy and 2009 vintage UOG resources are combined into the 2009 PCIA vintage rate.

Sales Forecast – PG&E inadvertently provided the sales forecast from its 2026 ERRA forecast in its Prepared Testimony.⁸⁸ This was a result of a collation error while preparing the filing.⁸⁹ PG&E correctly included the 2027 ERRA Forecast sales forecast in

⁸⁶ Confidential workpaper “08. ERRA_2027_Forecast_WP_PGE_20260515_Ch08_PCIA_CONF” and worksheet “CONF_CTC and PCIA_Interim SoD”, rows 284-287.

⁸⁷ PG&E’s response to DR CalCCA 005-Q002 (CONF), included in Attachment RAM-3.

⁸⁸ PG&E’s Prepared Testimony, at 13-AtchA-2.

⁸⁹ PG&E’s Response to DR CalCCA 002-Q013, included in Attachment RAM-3.

its workpapers, which are used to calculate the PCIA rate.⁹⁰ As a result, there was no rate impact from this error.

Retained RPS – CalCCA identified a concern where generation volumes for the 2013 vintage appeared negative in the workpapers to the PCIA.⁹¹ In response to a data request, PG&E communicated that it had inadvertently included a position for the balance of 2026 which drove generation volumes negative for that vintage.⁹² This error was corrected in the July errata filing⁹³ which increased the forecasted 2026 PABA under collected balance by \$35 million.⁹⁴

Retained RA – CalCCA identified a concern where it appeared there were two line items in PG&E PCIA workpapers referring to RA Capacity sales.⁹⁵ In response to a data request, PG&E communicated the “Residual RA Sales” item was included in error.⁹⁶ That error was corrected in the July errata filing, and PG&E identified that it had an impact of reducing the forecasted 2026 PABA under-collected balance by \$21.6 million⁹⁷ and reducing the PCIA indifference amount in the 2027 PCIA forecast by \$19.8 million.⁹⁸

IX. REVIEW OF PG&E’S 2026 YEAR-END PABA BALANCE

The PABA is a rolling true-up of the actual above-market costs of PG&E’s PCIA-eligible resource portfolio and the amount collected from customers through PCIA rates to

⁹⁰ Workpaper “13. ERRA_2027_Forecast_WP_PGE_20261015_Tables_13-5_13-6_13_7_13-8_13-9_13-10_13-11_AttaA_PUB.xlsx,” worksheet “B Results,” excel column AC, row 90.

⁹¹ Confidential workpaper “12. ERRA_2027_Forecast_WP_PGE_20260515_Ch12_BA_CONF” on worksheet “CONF_Retained RPS,” excel row 8.

⁹² PG&E’s Response to DR CalCCA 001-Q006, included in Attachment RAM-3.

⁹³ PG&E’s Response to DR CalCCA 007-Q003, included in Attachment RAM-3.

⁹⁴ PG&E’s Response to DR CalCCA 007-Q003-atch01, worksheet “Change”, line no. 25.

⁹⁵ Confidential workpaper “08. ERRA_2027_Forecast_WP_PGE_20260515_Ch08_PCIA_CONF_cost per project,” worksheet “CONF_CTC and PCIA_Interim SoD,” excel rows 354 and 378.

⁹⁶ PG&E’s Response to DR CalCCA 002-Q011, included in Attachment RAM-3.

⁹⁷ PG&E’s Response to DR CalCCA 007-Q003-atch01, worksheet “Change”, line no. 26.

⁹⁸ PG&E’s Response to DR CalCCA 007-Q001, included in Attachment RAM-3.

1 recover such above-market costs. Any over- or under-collection in the PABA through the
2 end of 2026 is used to modify the 2027 PCIA revenue requirement, by vintage.

3 Since its inception, the PABA has been a major component of the total PCIA
4 revenue requirement. In addition to being a large component of the PCIA revenue
5 requirement, the PABA balance has proven to be unpredictable, fluctuating by hundreds of
6 millions of dollars during the pendency of the ERRA application process. Given both the
7 variability and importance of this final balance, CalCCA closely tracks the monthly PABA
8 and ERRA balance updates and supporting information PG&E is now required to provide
9 throughout the ERRA Forecast application process.

10 In its Application filed in May 2026, PG&E's projection of the 2026 year-end
11 PABA balance (based on actual results through March 2026 and projections for April
12 through December 2026) indicated that by the end of 2026, the PABA will be under-
13 collected by \$351 million.⁹⁹ If everything went exactly according to the 2026 ERRA
14 Forecast, the PABA balance would be reduced to \$0 by the end of this year. An under-
15 collected PABA balancing account can be the result of many different factors, including
16 lower-than-expected customer revenues, higher-than-expected procurement costs, or
17 lower-than-expected market revenue from resource generation. Evaluating the
18 reasonableness of PG&E's projection that the 2026 PABA will be under-collected by
19 approximately \$351 million requires a comparison of the initial PCIA forecast for 2026
20 with the latest combination of actual results and projected activity in 2026.

⁹⁹ PG&E Prepared Testimony, Chapter 12, at 12-14, Table 12-3.

Using data from the 2026 ERRA Forecast and the PABA data provided in the PG&E's Master Data Request to CalCCA, I was able to prepare Table RAM-6 comparing the 2026 PCIA forecast to the 2026 PABA.

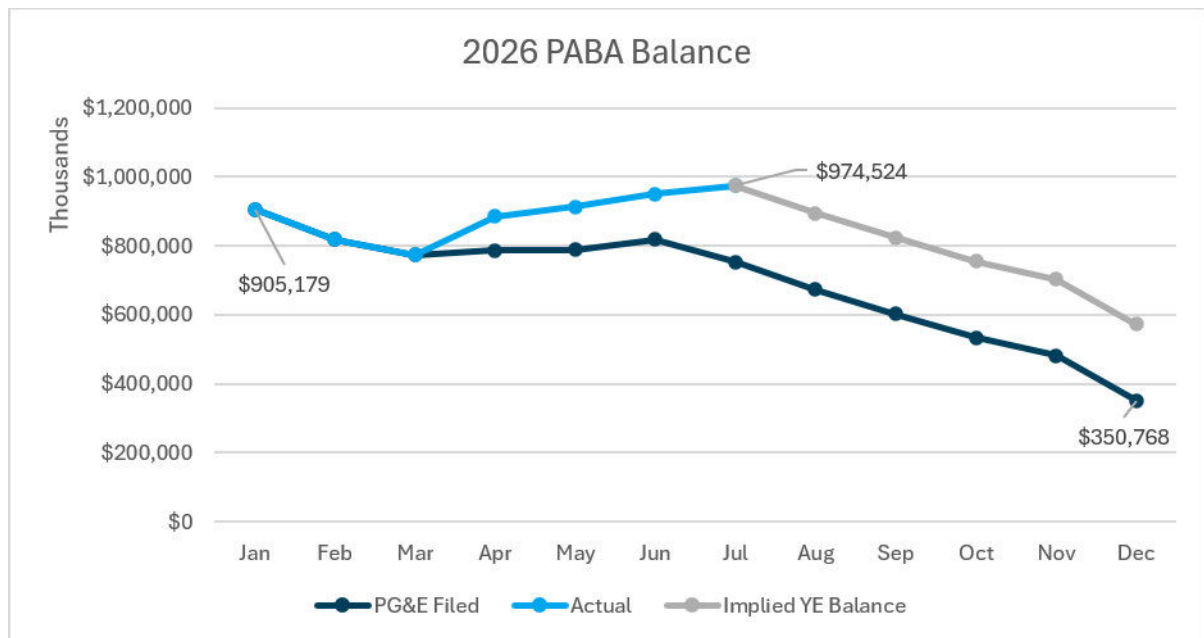
Table RAM-6: 2026 PCIA Forecast Versus 2026 PABA

Category	2026 PCIA Forecast (\$000)	2026 PABA Projection (\$000)	Variance (\$000)	Variance %
UOG (GRC) Costs	1,271,411			
Fuel, Purchased Power, Other Costs	2,082,645			
Total Portfolio Costs	3,354,055			
Brown Power Market Value	(1,252,649)			
RPS Market Value	(676,686)			
RA Market Value	(761,707)			
Total Market Value	(2,691,042)			
Indifference Amount	663,013			
Misc Adjustments/Transfers	9,020			
Adjusted PCIA Revenue Requirement	672,033			
Customer Revenue	(1,301,246)			
Subtotal Under/(Over) Recovery	(629,213)	(1,906,731)	(1,277,519)	
2025 PABA Ending Balance	2,228,893			
2025 ERRA Ending Balance	(1,600,334)			
Miscellaneous	655			
Total Under/(Over) Recovery	(0)	(1,906,731)		
2026 PABA				
Beginning Balance		2,270,492		
Activity		(1,906,731)		
Ending Balance		363,761		

PG&E’s testimony includes a description of the drivers it identified as causing the projected under collection in the 2026 PABA.¹⁰⁰ My analysis shows that the largest contributor to the under-collected \$364 million balance is a decline in the market value of energy by over [REDACTED] due to lower market prices.

Thus far, PG&E’s actual 2026 PABA balance has remained larger than forecasted. Actual results through July 2026 showed that the PABA balance was now under-collected by \$975 million, \$222 million larger than the \$753 million PG&E projected. Figure RAM-8 illustrates the variability in the monthly PABA balance in 2026 and the deviation of the actual balance from the forecast included in PG&E’s Application.

Figure RAM-8: PG&E Monthly PABA Balance

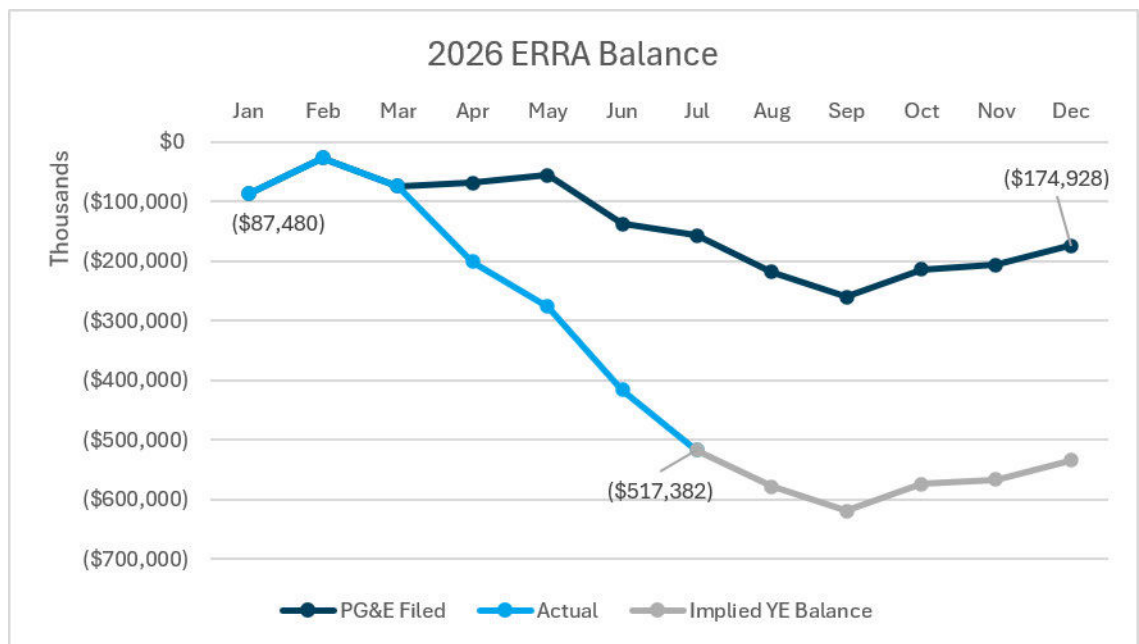


On the other hand, PG&E’s 2026 ERRA balancing account, which tracks the difference between the market cost to serve bundled load and revenue collected through bundled generation rates, is expected to be over-collected by \$175 million by the end of

¹⁰⁰ PG&E Prepared Testimony, at 12-13:26 through 12-16:19.

2026 due to the lower-than-expected wholesale market prices in 2026. To date, the actual ERRA balance has deviated substantially from the forecast, with a July over-collected balance of \$517 million as compared to the \$158 million forecast. Figure RAM-9 illustrates the variability in the monthly ERRA balance in 2026 and the deviation of the actual balance from the forecast included in PG&E's Application.

Figure RAM-9: PG&E Monthly ERRA Balance



Because the actual year-end PABA balance will be rolled into PCIA rates in 2027, an increase in the recorded PABA balance versus the projection PG&E included in its Application will put further upward pressure on the PCIA rates that bundled and unbundled customers ultimately pay. At the same time, including the year-end ERRA over-collection into rates in 2026 will put downward pressure on bundled customers' rates. It remains to be seen whether the balance of the summer months of 2026 will reduce the year-to-date under-collected PABA balance in a manner consistent with PG&E's initial expectations.

1 This concludes my testimony.

Attachment RAM-1

Curriculum Vitae of Ryan Matley



RYAN MATLEY

Principal

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Lakewood, CO 80228
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EDUCATION

Master of Economics in Public Utility
Regulation and Economics, New Mexico
State University

Bachelor of Science in Chemical
Engineering, University of Pennsylvania

KEY EXPERTISE

Cost of Service Analysis
Electric & Natural Gas Rate Design
Energy Policy Strategy Development
Expert Witness Testimony
FERC and State Commission Filings
Rate Case Support
Regulatory Finance
Revenue Requirements
Stakeholder Engagement
Strategic Planning & Execution
Utility Financial Planning and Forecasting

Mr. Ryan Matley is a strategic and results-driven energy professional with over 20 years of experience spanning regulatory finance, utility operations, product development, and consulting in the electric and natural gas industries. He joined NewGen in August 2025, bringing deep industry insight, strong analytical capabilities, and a collaborative approach to addressing utility challenges in a rapidly evolving energy landscape.

PRIOR RELEVANT EXPERIENCE

Xcel Energy

Manager, Regulatory Administration

Mr. Matley led a team responsible for all regulatory filings for the Public Service of Colorado natural gas utility, serving 1.5 million customers, and generating \$1.7 billion in annual revenue. He served as an expert witness on policy matters affecting cost recovery and future investments. Throughout his employment with Xcel, he progressively advanced throughout his tenure.

- Expanded the regulatory team from two to seven members within the first year, while consistently meeting deadlines.

- Developed, filed and completed a Gas Rate Case requesting a \$170 million rate increase, supporting the prudence of \$1 billion in capital investment.

- Acted as an expert witness on three key matters in first year: a rate case, a district steam system resource plan, and filing introducing the largest non-pipeline alternative portfolio in the country at the time.

Principal Rate Analyst

- Testified as cost-of-service expert in support of a comprehensive settlement for the 2021 New Mexico Retail Rate Case that resulted in a \$62 million electric rate increase.

- Managed the FERC Transmission Wholesale Formula Rate, including updating annual forecasts and true-ups and presenting to customers.

Product Development Team Lead

- Initiated, lead the development, and implemented a new renewable strategy intended to benefit corporate sustainability goals, that will allow customers to take credit for the renewable energy added to the grid.

- Lead the development and gained regulatory approval of the Renewable*Connect product in Colorado and Minnesota which made hundreds of megawatts of renewables available for customer subscription.

Associate Product Developer

- Managed 1,100 participant In-Home Device pilot to a successful completion on schedule and under budget.

RYAN MATLEY

Principal

Rocky Mountain Institute

Consultant, Electricity Practice

Mr. Matley managed research and consulting engagements at a non-profit “think and do” tank whose mission is to drive the efficient and restorative use of resources, led by a business for profit.

- Led the Industrial sector work stream for the State of Connecticut’s Comprehensive Energy Strategy, an initiative that charted a course to 2050 for a cleaner, cheaper and more reliable energy system for the State.
- Researched and wrote for the industry chapter of Reinventing Fire, a book written and published by the Rocky Mountain Institute that outlines a credible pathway to move the U.S. economy off of fossil fuels by 2050.

Pacific Gas & Electric Company

Senior Product Manager, Industrial Systems

Mr. Matley managed incentive product offerings through their lifecycle for technologies that contributed 7% of the electricity savings for PG&E’s Demand Side Management (DSM) programs. He held two positions with PG&E. He began as a Senior Program Manager of Emerging Technologies and was advanced to Senior Product Manager of Industrial Systems.

- Delivered improvements to the Agricultural Pump Efficiency Program that increased the cost-effectiveness by 7% and energy savings delivered by 58%.
- Developed portfolio annual strategic plan, delivered on annual goals, and oversaw project managers delivering towards program goals.
- Communicated assessment results to internal and external stakeholders through multiple presentations per year, conference submissions, internal meetings, external workshops, and direct customer support.

VOLUNTEERING

Mr. Matley has been an Expert Volunteer with the NARUC International Program on renewable tariffs in Mexico, Revenue Requirements for Togo, and Rate Case Processes in Sri Lanka.

Attachment RAM-2

Record of Testimony of Ryan Matley

Record of Testimony: Ryan Matley

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. Oncor Electric Delivery Company	59249 – Unified Tracker Mechanism	Transmission Cost of Service (TCOS), Transmission Cost Recovery Factor (TCRF), and Distribution Cost Recovery Factor (DCRF) revenue requirements and appropriateness of inclusions in new cost recovery mechanism under PURA 36.216	Public Utilities Commission of Texas	The Steering Committee of Cities Served by Oncor (OCSC)	2026
2. Lone Star Transmission, LLC	59245 – 2026 Electric Rate Case	Revenue Requirement for wholesale transmission provider in ERCOT, expense adjustments, cash working capital, rate case expenses, and large load/generator interconnection cost recovery.	Public Utilities Commission of Texas	Office of Public Utility Counsel (OPUC)	2026
3. Pacific Gas & Electric Company	A.25-05-009 – 2027 General Rate Case	Allocation of generation costs between Bundled and Departed Load customers, Hydro depreciation expense, forecasted generation expense and rate base.	California Public Utilities Commission	California Community Choice Association (CalCCA)	2026
4. American Electric Power (AEP) Texas	58315 – Unified Tracker Mechanism	Transmission Cost of Service (TCOS), Transmission Cost Recovery Factor (TCRF), and Distribution Cost Recovery Factor (DCRF) revenue requirements and class cost allocation; and appropriateness of inclusions in new cost recovery mechanism under PURA 36.216.	Public Utilities Commission of Texas	Cities Served by AEP Texas (Cities)	2025
5. Oncor Electric Delivery Company	58306 – 2025 Electric Rate Case	Revenue requirements, self-insurance reserve and securitization, transmission cost of service, gain on sale, rate case expenses, and labor expenses.	Public Utilities Commission of Texas	Office of Public Utility Counsel (OPUC)	2025
6. Public Service Company of Colorado	25A-0044EG - Mountain Energy Certificate of Public Convenience and Necessity (CPCN)	Policy testimony supporting approval of CPCN of gas supplemental supply and Non-Pipeline Alternatives in Mountain region of Colorado	Colorado Public Utilities Commission	Public Service Company of Colorado	2025
7. Public Service Company of Colorado	24AL-0049G - 2024 Gas Rate Case	Natural gas average rate model and revenue vs. revenue requirements analysis of new capital investment	Colorado Public Utilities Commission	Public Service Company of Colorado	2024

Record of Testimony: Ryan Matley

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. Public Service Company of Colorado	22A-0382ST - Steam Regulatory and Resource Plan	Policy testimony regarding the future of steam service in Denver relative to alternative technologies	Colorado Public Utilities Commission	Public Service Company of Colorado	2024
9. Southwestern Public Service	55255 - Solar and Battery Certificate of Convenience and Necessity (CCN)	Revenue requirements testimony to support approval of CCN for new solar and battery resources	Public Utilities Commission of Texas	Southwestern Public Service	2023
10. Southwestern Public Service	ER22-2746 - Transmission Formula Rate Proration	Correction of tax proration calculation in the removal of advanced distribution grid assets from transmission formula rate	Federal Energy Regulatory Commission	Southwestern Public Service	2022
11. Southwestern Public Service	20-00238-UT - 2020 New Mexico Electric Rate Case	Testified on revenue requirements to support settlement	New Mexico Public Regulation Commission	Southwestern Public Service	2020
12. Southwestern Public Service	18-00308-UT - Solar*Connect Community	Market research supporting customer demand for subscription solar program	New Mexico Public Regulation Commission	Southwestern Public Service	2018

Attachment RAM-3

Select Responses to CalCCA Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q003
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_001-Q003
Request Date:	June 1, 2026
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	June 15, 2026
PG&E Witness(es):	Various

SUBJECT: A.26-05-007: CALCCA's CONFIDENTIAL FIRST DATA REQUEST TO PG&E

QUESTION 003

Refer to Prepared Testimony, page 1-5 at 9-20.

- a. What does PG&E plan to include for UOG revenue requirement in the October update filing should its 2027 GRC revenue requirement not be approved at that time?
- b. What does PG&E plan to include in the 2027 AET process for UOG revenue requirement should its 2027 GRC revenue requirement not be approved at that time?
- c. In a scenario where its 2027 GRC revenue requirement is not approved by the time PG&E prepares the 2027 AET, would PG&E use the interim rate approach proposed in its May 7, 2026 Motion for Interim Rate Recovery in Application 25-05-009 to adjust the 2027 UOG revenue requirement on an interim basis for its PCIA calculations, subject to refund?

ANSWER 003

- a. Consistent with PG&E's Prepared Testimony, PG&E plans to include the currently authorized GRC revenue requirement in the October update filing should its 2027 GRC revenue requirement not be approved at that time.
- b. The 2027 GRC scoping memo denotes a final decision issued in May 2027, therefore PG&E does not anticipate the 2027 GRC revenue requirement will be approved in time to be incorporated into the 2027 Annual Electric True-up (AET) process which will set rates effective January 1, 2027. Because of the Commission's delay in issuing a final GRC decision, PG&E has requested interim rate relief (IRR) to go into effect January 1, 2027. Assuming PG&E's IRR request is either still pending or approved, PG&E anticipates that the Preliminary 2027 AET advice letter will reflect the UOG revenue requirement increase requested in

its IRR motion incremental to the currently authorized 2026 UOG revenue requirement.¹ For the Final AET, if IRR is approved by the CPUC for implementation in January 1, 2027 rates, the approved UOG revenue requirement increase will be incorporated incremental to the 2026 UOG revenue requirement. If IRR is not approved, PG&E will retain the 2026 UOG revenue requirement that it currently has in rates.

- c. Please see PG&E's response to subpart b.

¹ PG&E's preliminary AET advice letter is anticipated to be submitted November 16, 2026 in compliance with Resolution E-5217.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q006
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_001-Q006CONF
Request Date:	June 1, 2026
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	June 15, 2026
PG&E Witness(es):	Christa Hoffman

SUBJECT: A.26-05-007: CALCCA's CONFIDENTIAL FIRST DATA REQUEST TO PG&E

QUESTION 006

Refer to the Confidential workpaper "12.
ERRA_2027_Forecast_WP_PGE_20260515_Ch12_BA_CONF" on worksheet
"CONF Retained RPS", excel row 8.



ANSWER 006

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q006
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_001-Q006Supp01CONF
Request Date:	June 1, 2026
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	July 28, 2026
PG&E Witness(es):	Christa Hoffman/Angelia Vega

SUBJECT: A.26-05-007: CALCCA's CONFIDENTIAL FIRST DATA REQUEST TO PG&E

QUESTION 006

Refer to the Confidential workpaper "12.

ERRA_2027_Forecast_WP_PGE_20260515_Ch12_BA_CONF" on worksheet "CONF Retained RPS", excel row 8.

SUPPLEMENTAL ANSWER 006

PG&E inadvertently included a position for the balance of 2026 that drove generation volumes negative for that vintage. PG&E reflected the corrected values as part of its Errata to the Prepared Testimony filed on July 17, 2026. Please be aware that the April through August forecast will be replaced by actual recorded values in the Fall update before being replaced by actuals through November as part of 2026 year end balances that will be included in the AET.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_002-Q011
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_002-Q011
Request Date:	June 5, 2026
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	June 22, 2026
PG&E Witness(es):	George Clavier

SUBJECT: A.26-05-007: CALCCA'S CONFIDENTIAL SECOND DATA REQUEST TO PG&E

QUESTION 011

Refer to confidential workpaper "08. ERRA_2027_Forecast_WP_PGE_20260515_Ch08_PCIA_CONF_cost per project" on worksheet "CONF_CTC and PCIA_Interim SoD" on excel rows 354 and 378. Please describe what the ERRA Label "Residual Capacity Sales" and "Residual RA Sales" refers to, and what the distinction is between each item.

ANSWER 011

"Residual RA Sales" on line 378 refers to forecasted revenues from the sale of excess RA capacity. The derivation of the values shown on line 378 can be found in the workpaper 05. ERRA_2027_Forecast_WP_PGE_20260515-Ch05_4-6_4-17_5-4_5-15_5-16_5-17_RA Open Position-CONF—Tab 5_16_5_17. "Residual Capacity Sales" shown on line 358 was erroneously included in the worksheet. PG&E regrets the error, and will ensure that the "Residual Capacity Sales" line item is removed from the workbook in the Fall update.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_002-Q013
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_002-Q013
Request Date:	June 5, 2026
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	June 22, 2026
PG&E Witness(es):	Mark Coughlan

SUBJECT: A.26-05-007: CALCCA'S CONFIDENTIAL SECOND DATA REQUEST TO PG&E

QUESTION 013

Refer to Prepared Testimony page 13-AtchA-2 where PG&E states that the forecast total sales is 25,055,466,305 kWh. On worksheet "B Results" of the accompanying workpaper file "13. ERRA 2027_Forecast_WP_PGE_20261015_Tables 13-5_13-6_13-7_13-8_13-9_13-10_13-11_AttaA_PUB.xlsx," excel column AC, row 90, PG&E states that the forecast total sales is 22,918,685,439 kWh.

- a. Please explain why these forecast total system sales values are different.
- b. If these values were intended to be the same, which number is the one PG&E intended to file?
- c. If these values were intended to be the same, will PG&E submit an errata to update all calculations to use the intended number, and if so, when?

ANSWER 013

The values for the bundled sales in the two attachments are different because the value shown on page 13-AtchA-2 uses the forecast system sales presented in PG&E's 2026 May ERRA Application. This discrepancy is due to a collation error, resulting in the "Attachment A2" from last year's ERRA Application being inserted incorrectly. PG&E's 2027 May ERRA Application presents a forecasted total system sales of 22,918,685,439 kWh, and all ratemaking calculations in PG&E's 2027 ERRA May Application use this number. PG&E will submit a forthcoming Errata to include the correct file for "Attachment A2," and this file is also included as an attachment to this Data Request as "ERRA-2027-PGE-Forecast_DR_CalCCA_002-Q013-atc01."

PG&E will submit an Errata by (date) to replace Attachment A2 with the correct version.

Pacific Gas & Electric Company
2027 ERRRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

BOLD RESULTS

	Total Revenue At Present	Generation Revenue	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	WFC Revenue	RB Revenue	RBC Revenue	WH Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																						
Non-CARE	\$2,537,902,374	\$787,112,383	\$276,478,302	\$54,116,851	-\$24,558,087	-\$2,563,101	\$763,996	\$1,197,453,957	\$196,277,718	-\$122,933	\$32,855,215	\$51,081,587	-\$51,081,596	\$23,306,340	-\$1,647,230	\$132,688	\$88,161,205	\$0	\$0	-\$453,019	\$46,292,495	\$2,673,606,772
CARE	<u>\$922,443,183</u>	<u>\$520,667,445</u>	<u>\$186,512,676</u>	<u>\$36,507,309</u>	<u>-\$16,566,922</u>	<u>-\$1,729,072</u>	<u>\$515,398</u>	<u>\$133,624,444</u>	<u>\$40,169,551</u>	<u>-\$82,931</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>-\$1,111,252</u>	<u>\$89,514</u>	<u>\$36,766,179</u>	<u>\$0</u>	<u>\$0</u>	<u>-\$1,604,643</u>	<u>\$31,229,782</u>	<u>\$965,087,478</u>
TOTAL RES	\$3,460,345,557	\$1,307,779,828	\$462,990,978	\$90,624,160	-\$41,125,009	-\$4,292,173	\$1,279,394	\$1,331,078,401	\$236,447,270	-\$205,865	\$32,855,215	\$51,081,587	-\$51,081,596	\$23,306,340	-\$2,758,482	\$222,202	\$124,927,384	\$0	\$0	-\$1,957,662	\$77,522,277	\$3,638,694,250
SMALL L&P																						
B-1	\$679,607,711	\$206,358,635	\$51,436,531	\$14,856,975	-\$6,742,057	-\$474,562	\$142,136	\$359,732,076	\$49,143,400	-\$33,749	\$9,647,211	\$13,989,268	-\$13,989,270	\$6,627,601	-\$435,845	\$36,427	\$13,110,999	\$0	\$0		\$12,251,092	\$715,656,870
B-6	\$239,952,550	\$75,148,940	\$18,621,091	\$5,374,496	-\$2,438,932	-\$171,672	\$51,456	\$125,407,375	\$15,973,371	-\$12,209	\$3,489,638	\$5,060,269	-\$5,060,269	\$2,397,369	-\$157,667	\$13,178	\$4,742,891	\$0	\$0		\$4,431,821	\$252,871,145
A-15	\$312,174	\$94,266	\$23,519	\$6,794	-\$3,083	-\$217	\$65	\$165,970	\$22,502	-\$15	\$4,422	\$6,413	-\$6,413	\$3,038	-\$199	\$17	\$5,995	\$0	\$0		\$5,602	\$328,675
TC-1	<u>\$3,960,531</u>	<u>\$1,113,992</u>	<u>\$308,910</u>	<u>\$89,232</u>	<u>-\$40,493</u>	<u>-\$2,850</u>	<u>\$854</u>	<u>\$2,318,088</u>	<u>\$126,024</u>	<u>-\$203</u>	<u>\$58,084</u>	<u>\$84,227</u>	<u>-\$84,227</u>	<u>\$39,904</u>	<u>-\$2,618</u>	<u>\$219</u>	<u>\$78,746</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$73,581</u>	<u>\$4,161,471</u>
TOTAL SMALL	\$923,832,965	\$282,715,834	\$70,390,052	\$20,327,498	-\$9,224,566	-\$649,302	\$194,510	\$487,623,509	\$65,265,297	-\$46,176	\$13,199,356	\$19,140,177	-\$19,140,179	\$9,067,912	-\$596,329	\$49,840	\$17,938,632	\$0	\$0		\$16,762,096	\$973,018,161
MEDIUM L&P																						
B-10 T	\$128,319	\$60,851	\$21,286	\$5,397	-\$2,449	-\$155	\$59	\$28,832	\$16,043	-\$12	\$3,513	\$5,094	-\$5,094	\$1,332	-\$167	\$13	\$4,229	\$0	\$0		\$4,705	\$143,476
B-10 P	\$6,446,486	\$2,275,164	\$764,898	\$175,600	-\$79,887	-\$5,029	\$2,110	\$2,766,040	\$517,997	-\$399	\$114,304	\$165,751	-\$165,751	\$61,313	-\$5,448	\$431	\$137,596	\$0	\$0		\$153,079	\$6,877,970
B-10 S	<u>\$686,541,967</u>	<u>\$253,008,190</u>	<u>\$72,883,032</u>	<u>\$17,180,391</u>	<u>-\$7,796,417</u>	<u>-\$492,007</u>	<u>\$201,399</u>	<u>\$296,645,495</u>	<u>\$52,493,255</u>	<u>-\$39,027</u>	<u>\$11,118,089</u>	<u>\$16,122,165</u>	<u>-\$16,122,167</u>	<u>\$6,490,495</u>	<u>-\$532,979</u>	<u>\$42,124</u>	<u>\$13,462,099</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$14,976,943</u>	<u>\$729,641,080</u>
TOTAL MEDIUM	\$693,116,773	\$255,344,205	\$73,669,216	\$17,361,388	-\$7,878,553	-\$497,190	\$203,568	\$299,440,367	\$53,027,295	-\$39,439	\$11,235,906	\$16,293,010	-\$16,293,012	\$6,553,139	-\$538,594	\$42,568	\$13,603,923	\$0	\$0		\$15,134,727	\$736,662,526
B-19 CLASS																						
B-19 FIRM T	\$1,357,535	\$747,837	\$145,256	\$66,931	-\$30,373	-\$1,917	\$401	\$262,970	\$161,236	-\$152	\$43,568	\$63,177	-\$63,177	\$16,366	-\$1,968	\$164	\$52,445	\$0	\$0		\$55,321	\$1,518,085
B-19 V P	<u>\$1,287,912</u>	<u>\$672,326</u>	<u>\$205,891</u>	<u>\$50,169</u>	<u>-\$22,767</u>	<u>-\$1,437</u>	<u>\$569</u>	<u>\$236,074</u>	<u>\$144,890</u>	<u>-\$114</u>	<u>\$32,657</u>	<u>\$47,355</u>	<u>-\$47,355</u>	<u>\$12,267</u>	<u>-\$1,475</u>	<u>\$123</u>	<u>\$39,311</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$41,467</u>	<u>\$1,409,952</u>
Total B-19 T	\$2,645,446	\$1,420,163	\$351,147	\$117,100	-\$53,140	-\$3,353	\$970	\$499,044	\$306,126	-\$266	\$76,224	\$110,532	-\$110,532	\$28,634	-\$3,443	\$287	\$91,757	\$0	\$0		\$96,788	\$2,928,037
B-19 FIRM P	\$85,582,865	\$36,367,777	\$8,527,024	\$2,948,179	-\$1,337,876	-\$84,429	\$23,563	\$30,531,726	\$8,085,084	-\$6,697	\$1,919,067	\$2,782,809	-\$2,782,809	\$863,774	-\$86,692	\$7,229	\$2,310,115	\$0	\$0		\$2,436,790	\$92,504,633
B-19 V P	<u>\$31,502,541</u>	<u>\$13,935,219</u>	<u>\$3,184,974</u>	<u>\$1,151,447</u>	<u>-\$522,524</u>	<u>-\$32,975</u>	<u>\$8,801</u>	<u>\$10,382,240</u>	<u>\$3,186,935</u>	<u>-\$2,616</u>	<u>\$746,564</u>	<u>\$1,082,581</u>	<u>-\$1,082,581</u>	<u>\$336,030</u>	<u>-\$33,859</u>	<u>\$2,823</u>	<u>\$902,243</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$951,718</u>	<u>\$92,504,633</u>
Total B-19 P	\$117,085,405	\$50,302,996	\$11,711,998	\$4,099,626	-\$1,860,400	-\$117,404	\$32,364	\$40,913,966	\$11,272,018	-\$9,313	\$2,665,631	\$3,865,390	-\$3,865,390	\$1,199,804	-\$120,551	\$10,052	\$3,212,358	\$0	\$0		\$3,388,508	\$126,701,654
B-19 FIRM S	\$330,313,664	\$128,701,214	\$30,160,348	\$8,954,218	-\$4,063,401	-\$256,428	\$83,343	\$138,268,769	\$26,687,905	-\$20,341	\$5,828,595	\$8,451,954	-\$8,451,955	\$2,929,199	-\$263,302	\$21,955	\$7,016,288	\$0	\$0		\$7,401,026	\$351,449,385
B-19 V S	<u>\$544,867,876</u>	<u>\$217,283,661</u>	<u>\$44,378,046</u>	<u>\$15,357,110</u>	<u>-\$6,969,017</u>	<u>-\$439,792</u>	<u>\$122,631</u>	<u>\$228,106,097</u>	<u>\$43,935,071</u>	<u>-\$34,886</u>	<u>\$9,810,208</u>	<u>\$14,225,628</u>	<u>-\$14,225,628</u>	<u>\$4,930,185</u>	<u>-\$451,581</u>	<u>\$37,654</u>	<u>\$12,033,425</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$12,693,277</u>	<u>\$580,792,086</u>
Total B-19 S	\$875,181,541	\$345,984,874	\$74,538,394	\$24,311,328	-\$11,032,418	-\$696,221	\$205,973	\$366,374,865	\$70,622,976	-\$55,226	\$15,638,804	\$22,677,582	-\$22,677,584	\$7,859,384	-\$714,884	\$59,608	\$19,049,712	\$0	\$0		\$20,094,303	\$932,241,471
B-19 T	\$2,645,446	\$1,420,163	\$351,147	\$117,100	-\$53,140	-\$3,353	\$970	\$499,044	\$306,126	-\$266	\$76,224	\$110,532	-\$110,532	\$28,634	-\$3,443	\$287	\$91,757	\$0	\$0		\$96,788	\$2,928,037
B-19 P	\$117,085,405	\$50,302,996	\$11,711,998	\$4,099,626	-\$1,860,400	-\$117,404	\$32,364	\$40,913,966	\$11,272,018	-\$9,313	\$2,665,631	\$3,865,390	-\$3,865,390	\$1,199,804	-\$120,551	\$10,052	\$3,212,358	\$0	\$0		\$3,388,508	\$126,701,654
B-19 S	<u>\$875,181,541</u>	<u>\$345,984,874</u>	<u>\$74,538,394</u>	<u>\$24,311,328</u>	<u>-\$11,032,418</u>	<u>-\$696,221</u>	<u>\$205,973</u>	<u>\$366,374,865</u>	<u>\$70,622,976</u>	<u>-\$55,226</u>	<u>\$15,638,804</u>	<u>\$22,677,582</u>	<u>-\$22,677,584</u>	<u>\$7,859,384</u>	<u>-\$714,884</u>	<u>\$59,608</u>	<u>\$19,049,712</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$20,094,303</u>	<u>\$932,241,471</u>
TOTAL B-19	\$994,912,392	\$397,708,033	\$86,601,539	\$28,528,055	-\$12,945,957	-\$816,978	\$239,308	\$407,787,876	\$82,201,120	-\$64,805	\$18,380,659	\$26,653,503	-\$26,653,506	\$9,087,822	-\$838,879	\$69,947	\$22,353,827	\$0	\$0		\$23,579,599	\$1,061,871,162
STREETLIGHTS	\$32,593,229	\$7,739,573	\$2,002,410	\$667,440	-\$302,883	-\$18,379	\$5,533	\$21,147,936	\$965,729	-\$1,516	\$434,459	\$630,002	-\$630,002	\$280,093	-\$16,325	\$1,636	\$512,759	\$0	\$0		\$459,378	\$33,877,844
STANDBY																						
STANDBY T	\$73,592,599	\$32,938,331	\$9,701,107	\$3,450,458	-\$1,565,809	-\$102,614	\$26,807	\$18,973,306	\$8,573,280	-\$7,838	\$2,246,017	\$3,256,913	-\$3,256,914	\$775,303	-\$70,685	\$8,460	\$2,156,616	\$0	\$0		\$1,991,584	\$79,095,324
STANDBY P	\$7,297,881	\$1,800,999	\$492,722	\$139,383	-\$63,252	-\$4,145	\$1,334	\$4,368,769	\$368,921	-\$317	\$90,729	\$131,564	-\$131,564	\$108,694	-\$2,855	\$342	\$87,117	\$0	\$0		\$80,451	\$7,458,894
STANDBY S	<u>\$2,021,253</u>	<u>\$532,337</u>	<u>\$121,561</u>	<u>\$41,964</u>	<u>-\$19,043</u>	<u>-\$1,248</u>	<u>\$336</u>	<u>\$1,183,502</u>	<u>\$120,035</u>	<u>-\$95</u>	<u>\$27,316</u>	<u>\$39,610</u>	<u>-\$39,610</u>	<u>\$17,610</u>	<u>-\$860</u>	<u>\$103</u>	<u>\$26,228</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$24,221</u>	<u>\$2,073,968</u>
TOTAL STANDBY	\$82,911,733	\$35,272,667	\$10,305,391	\$3,631,805	-\$1,648,104	-\$108,007	\$28,477	\$24,525,578	\$9,062,237	-\$8,250	\$2,364,061	\$3,428,088	-\$3,428,088	\$901,608	-\$74,400	\$8,905	\$2,269,962	\$0	\$0		\$2,096,256	\$88,628,186
AGRICULTURE																						
AG-A1	\$81,858,443	\$18,380,630	\$4,398,012	\$1,384,433	-\$628,252	-\$41,172	\$12,153	\$53,196,699	\$4,688,937	-\$3,145	\$901,173	\$1,306,777	-\$1,306,777	\$550,483	-\$39,370	\$3,394	\$1,177,371	\$0	\$0		\$1,106,842	\$85,088,189
AG-A2	\$45,758,675	\$12,973,829	\$3,137,801	\$987,736	-\$448,232	-\$29,374	\$8,671	\$25,462,552	\$3,345,364	-\$2,244	\$642,950	\$932,332	-\$932,332	\$392,747	-\$28,089	\$2,422	\$840,006	\$0	\$0		\$789,687	\$48,075,826
AG-B	\$265,736,882	\$61,839,687	\$12,776,937	\$4,022,003	-\$1,025,174	-\$119,611	\$35,307	\$173,409,167	\$15,532,485	-\$9,136	\$2,618,054	\$3,796,399	-\$3,796,399	\$1,599,243	-\$114,377	\$9,861	\$3,420,455	\$0	\$0		\$3,215,556	\$276,410,455
AG-C	<u>\$897,381,025</u>	<u>\$271,003,895</u>	<u>\$65,501,950</u>	<u>\$20,619,106</u>	<u>-\$9,356,897</u>	<u>-\$813,195</u>	<u>\$181,003</u>	<u>\$470,407,847</u>	<u>\$84,051,093</u>	<u>-\$46,839</u>	<u>\$13,421,655</u>	<u>\$19,462,530</u>	<u>-\$19,462,532</u>	<u>\$8,198,640</u>	<u>-\$586,362</u>	<u>\$50,555</u>	<u>\$17,535,225</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$16,484,795</u>	<u>\$938,852,471</u>
TOTAL AG	\$1,280,735,024	\$364,198,041	\$85,814,700	\$27,013,279	-\$12,258,556	-\$803,352	\$237,133	\$722,476,264	\$87,617,879	-\$61,364	\$17,583,833	\$25,498,038	-\$25,498,040	\$10,741,113	-\$768,198	\$66,233	\$22,973,057	\$0	\$0		\$21,596,880	\$1,346,426,941
B-20 CLASS																						
B-20 FIRM T	\$169,032,248	\$104,962,502	\$23,687,165	\$8,696,934	-\$3,946,646	-\$210,743	\$65,455	\$13,900,823	\$21,455,277	-\$19,756	\$5,661,121	\$8,209,101	-\$8,209,102	\$1,638,050	-\$221,377	\$21,324	\$5,841,023	\$0	\$0		\$6,227,845	\$187,758,995
FPP T																						
TOTAL	\$169,032,248	\$104,962,502	\$23,687,165	\$8,696,934																		

Pacific Gas & Electric Company
2027 ERRRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

BOLD RESULTS

	Total Sales (kWh)	Revenue At Present Rates	Generation Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	RB Rates	RBC Rates	WH Rates	CTC Rates	ECRA Rates	NSGC Rates	Residential & Small Business AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
Class/Schedule																								
RESIDENTIAL																								
Non-CARE	5,960,717,805	\$0.42577	\$0.13205	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.20089	\$0.03293	-\$0.00002	\$0.00551	\$0.00857	-\$0.00857	\$0.00391	-\$0.00028	\$0.00002	\$0.01479	\$0.00000	\$0.00000	-\$0.00008	\$0.00777	\$0.44854	5.3%
CARE	4,021,211,547	\$0.22393	\$0.12948	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.03323	\$0.00999	-\$0.00002	\$0.00000	\$0.00000	\$0.00000	\$0.00000	-\$0.00028	\$0.00002	\$0.00914	\$0.00000	\$0.00000	-\$0.00037	\$0.00777	\$0.24000	4.6%
TOTAL RES	9,981,929,352	\$0.34666	\$0.13101	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.13335	\$0.02369	-\$0.00002	\$0.00329	\$0.00512	-\$0.00512	\$0.00233	-\$0.00028	\$0.00002	\$0.01252	\$0.00000	\$0.00000	-\$0.00020	\$0.00777	\$0.36453	5.2%
SMALL L&P																								
B-1	1,636,421,542	\$0.41530	\$0.12610	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.21983	\$0.03003	-\$0.00002	\$0.00590	\$0.00855	-\$0.00855	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.00749	\$0.43733	5.3%
B-6	591,973,902	\$0.40534	\$0.12695	\$0.03146	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.21185	\$0.02698	-\$0.00002	\$0.00589	\$0.00855	-\$0.00855	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.00749	\$0.42717	5.4%
A-15	748,293	\$0.41718	\$0.12597	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.22180	\$0.03007	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00406	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.00749	\$0.43923	5.3%
TC-1	9,828,512	\$0.40296	\$0.11334	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.23585	\$0.01282	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00406	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.00749	\$0.42341	5.1%
TOTAL SMALL	2,238,972,249	\$0.41261	\$0.12627	\$0.03144	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.21779	\$0.02915	-\$0.00002	\$0.00590	\$0.00855	-\$0.00855	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.00749	\$0.43458	5.3%
MEDIUM L&P																								
B-10 T	594,451	\$0.21586	\$0.10236	\$0.03581	\$0.00908	-\$0.00412	-\$0.00026	\$0.00010	\$0.04850	\$0.02699	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00224	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00791	\$0.24136	11.8%
B-10 P	19,341,510	\$0.33330	\$0.11763	\$0.03955	\$0.00908	-\$0.00412	-\$0.00026	\$0.00011	\$0.14301	\$0.02678	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00317	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00791	\$0.35561	6.7%
B-10 S	1,892,334,152	\$0.36280	\$0.13370	\$0.03851	\$0.00908	-\$0.00412	-\$0.00026	\$0.00011	\$0.15676	\$0.02774	-\$0.00002	\$0.00588	\$0.00852	-\$0.00852	\$0.00343	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00791	\$0.38558	6.3%
TOTAL MEDIUM	1,912,270,113	\$0.36246	\$0.13353	\$0.03852	\$0.00908	-\$0.00412	-\$0.00026	\$0.00011	\$0.15659	\$0.02773	-\$0.00002	\$0.00588	\$0.00852	-\$0.00852	\$0.00343	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00791	\$0.38523	6.3%
B-19 CLASS																								
B-19 FIRM T	7,372,107	\$0.18414	\$0.10144	\$0.01970	\$0.00908	-\$0.00412	-\$0.00026	\$0.00005	\$0.03567	\$0.02187	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.20592	11.8%
B-19 V T	5,525,899	\$0.23307	\$0.12167	\$0.03726	\$0.00908	-\$0.00412	-\$0.00026	\$0.00010	\$0.04272	\$0.02622	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.25515	9.5%
Total B-19 T	12,898,006	\$0.20511	\$0.11011	\$0.02722	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.03869	\$0.02373	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.22701	10.7%
B-19 FIRM P	324,727,198	\$0.26355	\$0.11199	\$0.02626	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.09402	\$0.02490	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.28487	8.1%
B-19 V P	126,826,110	\$0.24839	\$0.10988	\$0.02511	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.08186	\$0.02513	-\$0.00002	\$0.00589	\$0.00854	-\$0.00854	\$0.00265	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.26964	8.6%
Total B-19 P	451,553,308	\$0.25929	\$0.11140	\$0.02594	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.09061	\$0.02496	-\$0.00002	\$0.00590	\$0.00856	-\$0.00856	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.28059	8.2%
B-19 FIRM S	986,262,353	\$0.33491	\$0.13049	\$0.03058	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.14019	\$0.02706	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00297	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.35634	6.4%
B-19 V S	1,691,508,956	\$0.32212	\$0.12846	\$0.02624	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.13485	\$0.02597	-\$0.00002	\$0.00580	\$0.00841	-\$0.00841	\$0.00291	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.34336	6.6%
Total B-19 S	2,677,771,310	\$0.32683	\$0.12921	\$0.02784	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.13682	\$0.02637	-\$0.00002	\$0.00584	\$0.00847	-\$0.00847	\$0.00294	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.34814	6.5%
B-19 T	12,898,006	\$0.20511	\$0.11011	\$0.02722	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.03869	\$0.02373	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.22701	10.7%
B-19 P	451,553,308	\$0.25929	\$0.11140	\$0.02594	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.09061	\$0.02496	-\$0.00002	\$0.00590	\$0.00856	-\$0.00856	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.28059	8.2%
B-19 S	2,677,771,310	\$0.32683	\$0.12921	\$0.02784	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.13682	\$0.02637	-\$0.00002	\$0.00584	\$0.00847	-\$0.00847	\$0.00294	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.34814	6.5%
TOTAL B-19	3,142,222,624	\$0.31663	\$0.12657	\$0.02756	\$0.00908	-\$0.00412	-\$0.00026	\$0.00008	\$0.12978	\$0.02616	-\$0.00002	\$0.00585	\$0.00848	-\$0.00848	\$0.00289	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.00750	\$0.33794	6.7%
STREETLIGHTS	73,515,226	\$0.44335	\$0.10528	\$0.02724	\$0.00908	-\$0.00412	-\$0.00025	\$0.00008	\$0.28767	\$0.01314	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00381	-\$0.00022	\$0.00002	\$0.00697	\$0.00000	\$0.00000		\$0.00625	\$0.46083	3.9%
STANDBY																								
STANDBY T	380,050,694	\$0.19364	\$0.08667	\$0.02553	\$0.00908	-\$0.00412	-\$0.00027	\$0.00007	\$0.04992	\$0.02256	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00204	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00524	\$0.20812	7.5%
STANDBY P	15,352,313	\$0.47536	\$0.11731	\$0.03144	\$0.00908	-\$0.00412	-\$0.00027	\$0.00009	\$0.28457	\$0.02403	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00708	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00524	\$0.48585	2.2%
STANDBY S	4,622,121	\$0.43730	\$0.11517	\$0.02630	\$0.00908	-\$0.00412	-\$0.00027	\$0.00007	\$0.25605	\$0.02597	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00381	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00524	\$0.44870	2.6%
TOTAL STANDBY	400,025,127	\$0.20727	\$0.08818	\$0.02576	\$0.00908	-\$0.00412	-\$0.00027	\$0.00007	\$0.06131	\$0.02265	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00225	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00524	\$0.22156	6.9%
AGRICULTURE																								
AG-A1	152,488,397	\$0.53682	\$0.12054	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.34886	\$0.03075	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.00726	\$0.55800	3.9%
AG-A2	108,794,221	\$0.42060	\$0.11925	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.23404	\$0.03075	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.00726	\$0.44190	5.1%
AG B	443,003,493	\$0.59985	\$0.13969	\$0.02894	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.39144	\$0.03066	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.00726	\$0.62395	4.0%
AG C	2,271,091,514	\$0.39073	\$0.11933	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.29713	\$0.02820	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.00726	\$0.41251	5.6%
TOTAL AG	2,975,377,624	\$0.43044	\$0.12240	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.24282	\$0.02945	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.00726	\$0.45252	5.1%
B-20 CLASS																								
B-20 FIRM T	957,923,769	\$0.17646	\$0.10957	\$0.02473	\$0.00908	-\$0.00412	-\$0.00022	\$0.00007	\$0.01451	\$0.02240	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00171	-\$0.00023	\$0.00002	\$0.00610	\$0.00000	\$0.00000		\$0.00650	\$0.19601	11.1%
FPP T	957,923,769	\$0.17646	\$0.10957	\$0.02473	\$0.00908	-\$0.00412	-\$0.00022	\$0.00007	\$0.01451	\$0.02240	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00171	-\$0.00023	\$0.00002	\$0.00610	\$0.00000	\$0.00000		\$0.00650	\$0.19601	11.1%
TOTAL	957,																							

Pacific Gas & Electric Company
2027 ERRRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

ATTACHMENT RAM-3 PUBLIC

DA/CCA RESULTS																	Residential & Small Business			
Class/Schedule	Total Revenue At Present	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	WFC Revenue	RB Revenue	RBC Revenue	WH Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue
RESIDENTIAL																				
Non-CARE	\$4,210,256,041	\$593,722,084	\$116,212,988	-\$52,737,153	-\$5,504,120	\$1,640,646	\$2,423,338,597	\$378,649,530	-\$263,992	\$73,067,747	\$109,649,906	-\$109,649,913	\$50,049,094	-\$3,537,342	\$284,941	\$158,340,070	\$0	\$0	\$59,778,235	\$191,710,497
CARE	~~\$505,186,225~~	~~\$159,605,661~~	~~\$31,240,628~~	~~\$14,176,916~~	~~\$1,479,630~~	~~\$441,037~~	~~\$163,407,986~~	~~\$40,532,090~~	~~\$70,967~~	~~\$0~~	~~\$0~~	~~\$0~~	~~\$0~~	~~\$950,915~~	~~\$76,598~~	~~\$37,096,886~~	~~\$0~~	~~\$0~~	~~\$57,820,573~~	~~\$46,420,778~~
TOTAL RES	\$4,715,442,266	\$753,327,745	\$147,453,616	-\$66,914,068	-\$6,983,750	\$2,081,683	\$2,586,746,583	\$419,181,619	-\$334,959	\$73,067,747	\$109,649,906	-\$109,649,913	\$50,049,094	-\$4,488,257	\$361,539	\$195,436,956	\$0	\$0	\$1,957,662	\$238,131,275
SMALL L&P																				
B-1	\$1,259,699,188	\$120,208,742	\$34,723,618	-\$15,757,488	-\$1,109,144	\$332,175	\$815,703,092	\$114,848,681	-\$78,879	\$22,542,687	\$32,688,794	-\$32,688,797	\$15,487,757	-\$1,018,654	\$85,138	\$30,642,936	\$0	\$0		\$55,026,175
B-6	\$369,241,509	\$36,150,419	\$10,438,677	-\$4,737,045	-\$333,433	\$99,895	\$239,713,451	\$31,003,195	-\$23,713	\$6,767,525	\$9,813,481	-\$9,813,482	\$4,651,017	-\$306,230	\$25,594	\$9,211,935	\$0	\$0		\$16,452,420
A-15	\$360,398	\$30,478	\$8,804	-\$3,995	-\$281	\$84	\$237,560	\$29,160	-\$20	\$5,729	\$8,307	-\$8,307	\$3,937	-\$258	\$22	\$7,769	\$0	\$0		\$17,382
TC-1	\$9,483,312	\$912,026	\$263,450	-\$119,553	-\$8,415	\$2,520	\$6,532,393	\$372,073	-\$598	\$171,488	\$248,672	-\$248,672	\$117,812	-\$7,729	\$646	\$232,489	\$0	\$0		\$426,053
TOTAL SMALL	\$1,638,784,407	\$157,301,665	\$45,434,548	-\$20,618,080	-\$1,451,273	\$434,675	\$1,062,186,497	\$146,253,108	-\$103,210	\$29,487,429	\$42,759,254	-\$42,759,258	\$20,260,523	-\$1,332,870	\$111,400	\$40,095,129	\$0	\$0		\$71,922,030
MEDIUM L&P																				
B-10 T	\$312,935	\$48,490	\$19,827	-\$8,997	-\$568	\$134	\$71,174	\$58,937	-\$45	\$12,906	\$18,715	-\$18,715	\$4,892	-\$615	\$49	\$15,536	\$0	\$0		\$29,464
B-10 P	\$12,761,466	\$2,102,765	\$443,164	-\$201,107	-\$12,691	\$5,806	\$6,641,619	\$1,301,956	-\$1,007	\$286,541	\$415,509	-\$415,509	\$153,700	-\$13,748	\$1,087	\$347,252	\$0	\$0		\$735,673
B-10 S	~~\$1,264,748,618~~	~~\$168,737,510~~	~~\$43,702,635~~	~~\$19,832,143~~	~~\$1,251,543~~	~~\$466,276~~	~~\$700,239,216~~	~~\$133,697,247~~	~~\$99,276~~	~~\$28,335,481~~	~~\$41,088,832~~	~~\$41,088,836~~	~~\$16,545,674~~	~~\$1,355,766~~	~~\$107,153~~	~~\$34,244,226~~	~~\$0~~	~~\$0~~	~~\$71,469,067~~	~~\$71,469,067~~
TOTAL MEDIUM	\$1,277,823,019	\$170,888,764	\$44,165,626	-\$20,042,246	-\$1,264,802	\$472,216	\$706,952,009	\$135,058,139	-\$100,328	\$28,634,927	\$41,523,055	-\$41,523,059	\$16,704,266	-\$1,370,129	\$108,288	\$34,607,013	\$0	\$0		\$72,234,204
B-19 CLASS																				
B-19 FIRM T	\$2,538,914	\$459,913	\$171,091	-\$77,641	-\$4,900	\$1,271	\$582,694	\$412,156	-\$389	\$111,369	\$161,494	-\$161,494	\$41,835	-\$5,031	\$419	\$134,062	\$0	\$0		\$255,383
B-19 V T	~~\$709,553~~	~~\$139,470~~	~~\$44,538~~	~~\$20,211~~	~~\$1,275~~	~~\$385~~	~~\$158,556~~	~~\$128,626~~	~~\$101~~	~~\$28,991~~	~~\$42,040~~	~~\$42,040~~	~~\$10,890~~	~~\$1,310~~	~~\$109~~	~~\$34,899~~	~~\$0~~	~~\$0~~	~~\$62,713~~	~~\$62,713~~
Total B-19 T	\$3,248,466	\$599,383	\$215,629	-\$97,852	-\$6,175	\$1,656	\$741,250	\$540,782	-\$490	\$140,360	\$203,534	-\$203,534	\$52,726	-\$6,341	\$529	\$168,961	\$0	\$0		\$318,096
B-19 FIRM P	\$111,335,820	\$14,930,121	\$5,528,728	-\$2,508,923	-\$158,330	\$41,257	\$53,364,981	\$15,161,980	-\$12,559	\$3,598,831	\$5,218,609	-\$5,218,609	\$1,619,838	-\$162,575	\$13,556	\$4,332,165	\$0	\$0		\$7,166,204
B-19 V P	~~\$55,144,693~~	~~\$7,610,809~~	~~\$2,688,461~~	~~\$1,220,017~~	~~\$76,991~~	~~\$21,031~~	~~\$25,050,875~~	~~\$7,460,016~~	~~\$6,107~~	~~\$1,750,008~~	~~\$2,537,659~~	~~\$2,537,659~~	~~\$787,681~~	~~\$79,055~~	~~\$6,592~~	~~\$2,106,607~~	~~\$0~~	~~\$0~~	~~\$3,978,027~~	~~\$3,978,027~~
Total B-19 P	\$166,480,513	\$22,540,930	\$8,217,190	-\$3,728,939	-\$235,321	\$62,288	\$78,415,856	\$22,621,996	-\$18,666	\$5,348,839	\$7,756,268	-\$7,756,268	\$2,407,519	-\$241,630	\$20,148	\$6,438,772	\$0	\$0		\$11,144,230
B-19 FIRM S	\$922,515,464	\$114,479,758	\$32,616,462	-\$14,801,266	-\$934,060	\$316,344	\$527,239,329	\$97,081,342	-\$74,092	\$21,180,531	\$30,713,552	-\$30,713,555	\$10,645,867	-\$959,100	\$79,971	\$25,557,395	\$0	\$0		\$46,893,562
B-19 V S	~~\$1,468,517,827~~	~~\$157,868,873~~	~~\$64,954,121~~	~~\$29,476,011~~	~~\$1,860,137~~	~~\$436,242~~	~~\$783,743,109~~	~~\$187,290,023~~	~~\$147,551~~	~~\$42,043,666~~	~~\$60,966,855~~	~~\$60,966,861~~	~~\$21,119,385~~	~~\$1,910,002~~	~~\$159,259~~	~~\$50,896,326~~	~~\$0~~	~~\$0~~	~~\$87,151,018~~	~~\$87,151,018~~
Total B-19 S	\$2,391,033,291	\$272,348,631	\$97,570,583	-\$44,277,277	-\$2,794,197	\$752,586	\$1,310,982,438	\$284,371,365	-\$221,643	\$63,224,196	\$91,680,407	-\$91,680,416	\$31,765,252	-\$2,869,103	\$239,231	\$76,453,721	\$0	\$0		\$134,044,580
B-19 T	\$3,248,466	\$599,383	\$215,629	-\$97,852	-\$6,175	\$1,656	\$741,250	\$540,782	-\$490	\$140,360	\$203,534	-\$203,534	\$52,726	-\$6,341	\$529	\$168,961	\$0	\$0		\$318,096
B-19 P	\$166,480,513	\$22,540,930	\$8,217,190	-\$3,728,939	-\$235,321	\$62,288	\$78,415,856	\$22,621,996	-\$18,666	\$5,348,839	\$7,756,268	-\$7,756,268	\$2,407,519	-\$241,630	\$20,148	\$6,438,772	\$0	\$0		\$11,144,230
B-19 S	~~\$2,391,033,291~~	~~\$272,348,631~~	~~\$97,570,583~~	~~\$44,277,277~~	~~\$2,794,197~~	~~\$752,586~~	~~\$1,310,982,438~~	~~\$284,371,365~~	~~\$221,643~~	~~\$63,224,196~~	~~\$91,680,407~~	~~\$91,680,416~~	~~\$31,765,252~~	~~\$2,869,103~~	~~\$239,231~~	~~\$76,453,721~~	~~\$0~~	~~\$0~~	~~\$134,044,580~~	~~\$134,044,580~~
TOTAL B-19	\$2,560,762,270	\$295,488,944	\$106,003,401	-\$48,104,068	-\$3,035,694	\$816,530	\$1,390,139,544	\$307,534,144	-\$240,800	\$68,713,396	\$99,640,208	-\$99,640,218	\$34,225,497	-\$3,117,073	\$259,907	\$83,061,454	\$0	\$0		\$145,506,907
STREETLIGHTS	\$52,388,401	\$4,430,575	\$1,476,793	-\$670,165	-\$40,665	\$12,243	\$37,935,474	\$2,075,975	-\$3,355	\$961,293	\$1,393,956	-\$1,393,956	\$619,740	-\$36,121	\$3,621	\$1,134,542	\$0	\$0		\$1,983,536
STANDBY																				
STANDBY T	\$18,452,125	\$3,401,553	\$1,383,527	-\$627,841	-\$41,145	\$9,400	\$5,163,435	\$3,437,621	-\$3,143	\$900,584	\$1,305,922	-\$1,305,922	\$310,873	-\$28,343	\$3,392	\$864,737	\$0	\$0		\$1,495,081
STANDBY P	\$4,068,395	\$315,984	\$64,698	-\$29,360	-\$1,924	\$873	\$3,290,676	\$171,244	-\$147	\$42,114	\$61,069	-\$61,069	\$50,453	-\$1,325	\$159	\$40,438	\$0	\$0		\$45,149
STANDBY S	\$747,355	\$62,424	\$25,237	-\$11,453	-\$751	\$172	\$468,251	\$72,189	-\$57	\$16,428	\$23,821	-\$23,821	\$10,591	-\$517	\$62	\$15,774	\$0	\$0		\$25,862
TOTAL STANDBY	\$23,267,875	\$3,779,961	\$1,473,462	-\$668,653	-\$43,820	\$10,445	\$8,922,362	\$3,681,055	-\$3,347	\$959,125	\$1,390,812	-\$1,390,812	\$371,917	-\$30,185	\$3,613	\$920,948	\$0	\$0		\$1,566,092
AGRICULTURE																				
AG-A1	\$31,819,330	\$2,126,085	\$669,262	-\$303,709	-\$19,903	\$5,875	\$24,050,945	\$2,266,723	-\$1,520	\$435,645	\$631,721	-\$631,721	\$266,114	-\$19,032	\$1,641	\$569,164	\$0	\$0		\$946,751
AG-A2	\$16,127,153	\$1,539,609	\$484,648	-\$219,932	-\$14,413	\$4,254	\$10,496,733	\$1,641,453	-\$1,101	\$315,473	\$457,463	-\$457,463	\$192,707	-\$13,782	\$1,188	\$412,162	\$0	\$0		\$682,895
AG-B	\$72,278,426	\$5,118,289	\$1,611,166	-\$731,143	-\$47,915	\$14,143	\$53,520,729	\$6,222,129	-\$3,660	\$1,048,761	\$1,520,792	-\$1,520,792	\$640,638	-\$45,818	\$3,950	\$1,370,194	\$0	\$0		\$2,258,653
AG C	~~\$361,269,059~~	~~\$42,088,449~~	~~\$13,248,861~~	~~\$6,012,299~~	~~\$394,010~~	~~\$116,304~~	~~\$213,395,631~~	~~\$41,156,197~~	~~\$30,096~~	~~\$8,624,120~~	~~\$12,505,700~~	~~\$12,505,701~~	~~\$5,268,058~~	~~\$376,768~~	~~\$32,485~~	~~\$11,267,304~~	~~\$0~~	~~\$0~~	~~\$18,462,358~~	~~\$18,462,358~~
TOTAL AG	\$481,493,968	\$50,872,432	\$16,013,937	-\$7,267,083	-\$476,241	\$140,577	\$301,464,038	\$51,286,503	-\$36,378	\$10,423,999	\$15,115,676	-\$15,115,677	\$6,367,517	-\$455,401	\$39,264	\$13,618,824	\$0	\$0		\$22,350,657
B-20 CLASS																				
B-20 FIRM T	\$357,582,184	\$85,467,140	\$33,883,754	-\$15,376,359	-\$821,068	\$236,173	\$44,715,020	\$83,590,991	-\$76,971	\$20,691,482	\$30,004,391	-\$30,004,394	\$6,381,936	-\$862,497	\$83,079	\$22,756,962	\$0	\$0		\$35,374,005
FPP T	~~\$10,123,742~~	~~\$0~~	~~\$0~~	~~\$0~~	~~\$0~~	~~\$0~~	~~\$3,640,529~~	~~\$6,468,107~~	~~\$~~											

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027

Revenue and Average Rate Summary without GHG Revenue Return

DA/CCA RESULTS

DA/CRA RESULTS																			Residential & Small Business									
	Total Proposed Revenue	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	RB Rates	RB Credit Rates	WH Rates	CTC Rates	ECRA Rates	NSGC Rates	AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change				
RESIDENTIAL																												
Non-CARE	\$3,984,751,815	\$12,800,338,582	\$0.32892	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.18932	\$0.02958	-\$0.00002	\$0.00571	\$0.00857	-\$0.00857	\$0.00391	-\$0.00028	\$0.00002	\$0.01237	\$0.00000	\$0.00000	\$0.00467	\$0.01498	\$0.31130	-5.4%				
CARE	<u>\$404,322,662</u>	<u>\$3,441,011,083</u>	\$0.14681	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.04749	\$0.01178	-\$0.00002	\$0.00000	\$0.00000	\$0.00000	\$0.00000	-\$0.00028	\$0.00002	\$0.01078	\$0.00000	\$0.00000	-\$0.01680	\$0.01349	\$0.11750	-20.0%				
TOTAL RES	\$4,389,074,477	\$16,241,349,665	\$0.29034	\$0.04638	\$0.00908	-\$0.00412	-\$0.00043	\$0.00013	\$0.15927	\$0.02581	-\$0.00002	\$0.00450	\$0.00675	-\$0.00675	\$0.00308	-\$0.00028	\$0.00002	\$0.01203	\$0.00000	\$0.00000	\$0.00012	\$0.01466	\$0.27024	-6.9%				
SMALL L&P																												
B-1	\$1,191,636,834	3,824,632,939	\$0.32936	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.21328	\$0.03003	-\$0.00002	\$0.00589	\$0.00855	-\$0.00855	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.01439	\$0.31157	-5.4%				
B-6	\$349,113,709	1,149,768,119	\$0.32114	\$0.03144	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.20849	\$0.02696	-\$0.00002	\$0.00589	\$0.00854	-\$0.00854	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.01431	\$0.30364	-5.5%				
A-15	\$336,369	969,694	\$0.37166	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.24498	\$0.03007	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00406	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.01793	\$0.34688	-6.7%				
TC-1	<u>\$8,894,654</u>	<u>29,017,651</u>	<u>\$0.32681</u>	<u>\$0.03143</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00029</u>	<u>\$0.00009</u>	<u>\$0.22512</u>	<u>\$0.01282</u>	<u>-\$0.00002</u>	<u>\$0.00591</u>	<u>\$0.00857</u>	<u>-\$0.00857</u>	<u>\$0.00406</u>	<u>-\$0.00027</u>	<u>\$0.00002</u>	<u>\$0.00801</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01468</u>	<u>\$0.30653</u>	<u>-6.2%</u>				
TOTAL SMALL	\$1,549,981,566	5,004,388,403	\$0.32747	\$0.03143	\$0.00908	-\$0.00412	-\$0.00029	\$0.00009	\$0.21225	\$0.02922	-\$0.00002	\$0.00589	\$0.00854	-\$0.00854	\$0.00405	-\$0.00027	\$0.00002	\$0.00801	\$0.00000	\$0.00000		\$0.01437	\$0.30972	-5.4%				
MEDIUM L&P																												
B-10 T	\$251,182	2,183,805	\$0.14330	\$0.02220	\$0.00908	-\$0.00412	-\$0.00026	\$0.00006	\$0.03259	\$0.02699	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00224	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01349	\$0.11502	-19.7%				
B-10 P	\$11,791,009	48,812,294	\$0.26144	\$0.04308	\$0.00908	-\$0.00412	-\$0.00026	\$0.00012	\$0.13606	\$0.02667	-\$0.00002	\$0.00587	\$0.00851	-\$0.00851	\$0.00315	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01507	\$0.24156	-7.6%				
B-10 S	<u>\$1,175,005,753</u>	<u>4,813,626,823</u>	<u>\$0.26274</u>	<u>\$0.03505</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00026</u>	<u>\$0.00010</u>	<u>\$0.14547</u>	<u>\$0.02777</u>	<u>-\$0.00002</u>	<u>\$0.00589</u>	<u>\$0.00854</u>	<u>-\$0.00854</u>	<u>\$0.00344</u>	<u>-\$0.00028</u>	<u>\$0.00002</u>	<u>\$0.00711</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01485</u>	<u>\$0.24410</u>	<u>-7.1%</u>				
TOTAL MEDIUM	\$1,187,047,944	4,864,622,922	\$0.26268	\$0.03513	\$0.00908	-\$0.00412	-\$0.00026	\$0.00010	\$0.14533	\$0.02776	-\$0.00002	\$0.00589	\$0.00854	-\$0.00854	\$0.00343	-\$0.00028	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01485	\$0.24402	-7.1%				
B-19 CLASS																												
B-19 FIRM T	\$2,082,234	18,844,790	\$0.13473	\$0.02441	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.03092	\$0.02187	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01355	\$0.11049	-18.0%				
B-19 V T	<u>\$586,281</u>	<u>4,905,627</u>	<u>\$0.14464</u>	<u>\$0.02843</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00026</u>	<u>\$0.00008</u>	<u>\$0.03232</u>	<u>\$0.02622</u>	<u>-\$0.00002</u>	<u>\$0.00591</u>	<u>\$0.00857</u>	<u>-\$0.00857</u>	<u>\$0.00222</u>	<u>-\$0.00027</u>	<u>\$0.00002</u>	<u>\$0.00711</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01278</u>	<u>\$0.11951</u>	<u>-17.4%</u>				
Total B-19 T	\$2,668,515	23,750,418	\$0.13678	\$0.02524	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.03121	\$0.02277	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01339	\$0.11236	-17.9%				
B-19 FIRM P	\$102,915,275	608,961,804	\$0.18283	\$0.02452	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.08763	\$0.02490	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01177	\$0.16900	-7.8%				
B-19 V P	<u>\$50,077,936</u>	<u>296,120,586</u>	<u>\$0.18622</u>	<u>\$0.02570</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00026</u>	<u>\$0.00007</u>	<u>\$0.08460</u>	<u>\$0.02519</u>	<u>-\$0.00002</u>	<u>\$0.00591</u>	<u>\$0.00857</u>	<u>-\$0.00857</u>	<u>\$0.00266</u>	<u>-\$0.00027</u>	<u>\$0.00002</u>	<u>\$0.00711</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01343</u>	<u>\$0.16911</u>	<u>-9.2%</u>				
Total B-19 P	\$152,993,211	905,082,389	\$0.18394	\$0.02490	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.08664	\$0.02499	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01231	\$0.16904	-8.1%				
B-19 FIRM S	\$859,322,039	3,592,540,254	\$0.25679	\$0.03187	\$0.00908	-\$0.00412	-\$0.00026	\$0.00009	\$0.14676	\$0.02702	-\$0.00002	\$0.00590	\$0.00855	-\$0.00855	\$0.00296	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01305	\$0.23920	-6.9%				
B-19 V S	<u>\$1,362,268,315</u>	<u>7,154,371,703</u>	<u>\$0.20526</u>	<u>\$0.02207</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00026</u>	<u>\$0.00006</u>	<u>\$0.10955</u>	<u>\$0.02618</u>	<u>-\$0.00002</u>	<u>\$0.00588</u>	<u>\$0.00852</u>	<u>-\$0.00852</u>	<u>\$0.00295</u>	<u>-\$0.00027</u>	<u>\$0.00002</u>	<u>\$0.00711</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01218</u>	<u>\$0.19041</u>	<u>-7.2%</u>				
Total B-19 S	\$2,221,590,354	10,746,911,957	\$0.22249	\$0.02534	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.12199	\$0.02646	-\$0.00002	\$0.00588	\$0.00853	-\$0.00853	\$0.00296	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01247	\$0.20672	-7.1%				
B-19 T	\$2,668,515	23,750,418	\$0.13678	\$0.02524	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.03121	\$0.02277	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00222	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01339	\$0.11236	-17.9%				
B-19 P	\$152,993,211	905,082,389	\$0.18394	\$0.02490	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.08664	\$0.02499	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00266	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01231	\$0.16904	-8.1%				
B-19 S	<u>\$2,221,590,354</u>	<u>10,746,911,957</u>	<u>\$0.22249</u>	<u>\$0.02534</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00026</u>	<u>\$0.00007</u>	<u>\$0.12199</u>	<u>\$0.02646</u>	<u>-\$0.00002</u>	<u>\$0.00588</u>	<u>\$0.00853</u>	<u>-\$0.00853</u>	<u>\$0.00296</u>	<u>-\$0.00027</u>	<u>\$0.00002</u>	<u>\$0.00711</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01247</u>	<u>\$0.20672</u>	<u>-7.1%</u>				
TOTAL B-19	\$2,377,252,080	11,675,744,764	\$0.21932	\$0.02531	\$0.00908	-\$0.00412	-\$0.00026	\$0.00007	\$0.11906	\$0.02634	-\$0.00002	\$0.00589	\$0.00853	-\$0.00853	\$0.00293	-\$0.00027	\$0.00002	\$0.00711	\$0.00000	\$0.00000		\$0.01246	\$0.20361	-7.2%				
STREETLIGHTS																												
	\$49,883,486	162,661,392	\$0.32207	\$0.02724	\$0.00908	-\$0.00412	-\$0.00025	\$0.00008	\$0.23322	\$0.01276	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00381	-\$0.00022	\$0.00002	\$0.00697	\$0.00000	\$0.00000		\$0.01219	\$0.30667	-4.8%				
STANDBY																												
STANDBY T	\$16,269,731	152,388,622	\$0.12109	\$0.02232	\$0.00908	-\$0.00412	-\$0.00027	\$0.00006	\$0.03388	\$0.02256	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00204	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00981	\$0.10676	-11.8%				
STANDBY P	\$3,989,032	7,126,171	\$0.57091	\$0.04434	\$0.00908	-\$0.00412	-\$0.00027	\$0.00012	\$0.46177	\$0.02403	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00708	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00634	\$0.55977	-2.0%				
STANDBY S	<u>\$684,212</u>	<u>2,779,734</u>	<u>\$0.26886</u>	<u>\$0.02246</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00027</u>	<u>\$0.00006</u>	<u>\$0.16845</u>	<u>\$0.02597</u>	<u>-\$0.00002</u>	<u>\$0.00591</u>	<u>\$0.00857</u>	<u>-\$0.00857</u>	<u>\$0.00381</u>	<u>-\$0.00019</u>	<u>\$0.00002</u>	<u>\$0.00567</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.00930</u>	<u>\$0.24614</u>	<u>-8.4%</u>				
TOTAL STANDBY	\$20,942,975	162,294,527	\$0.14337	\$0.02329	\$0.00908	-\$0.00412	-\$0.00027	\$0.00006	\$0.05498	\$0.02268	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00229	-\$0.00019	\$0.00002	\$0.00567	\$0.00000	\$0.00000		\$0.00965	\$0.12904	-10.0%				
AGRICULTURE																												
AG-A1	\$30,994,039	73,715,858	\$0.43165	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.32627	\$0.03075	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.01284	\$0.42045	-2.6%				
AG-A2	\$15,521,895	53,381,516	\$0.30211	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.19664	\$0.03075	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.01279	\$0.29077	-3.8%				
AG B	\$70,980,117	177,461,934	\$0.40729	\$0.02884	\$0.00908	-\$0.00412	-\$0.00027	\$0.00008	\$0.30159	\$0.03506	-\$0.00002	\$0.00591	\$0.00857	-\$0.00857	\$0.00361	-\$0.00026	\$0.00002	\$0.00772	\$0.00000	\$0.00000		\$0.01273	\$0.39997	-1.8%				
AG C	<u>\$346,846,592</u>	<u>1,459,295,785</u>	<u>\$0.24756</u>	<u>\$0.02884</u>	<u>\$0.00908</u>	<u>-\$0.00412</u>	<u>-\$0.00027</u>	<u>\$0.00008</u>	<u>\$0.14623</u>	<u>\$0.02820</u>	<u>-\$0.00002</u>	<u>\$0.00591</u>	<u>\$0.00857</u>	<u>-\$0.00857</u>	<u>\$0.00361</u>	<u>-\$0.00026</u>	<u>\$0.00002</u>	<u>\$0.00772</u>	<u>\$0.00000</u>	<u>\$0.00000</u>		<u>\$0.01265</u>	<u>\$0.23768</u>	<u>-4.0%</u>				
TOTAL AG	\$464,342,643	\$1,763,855,093</																										

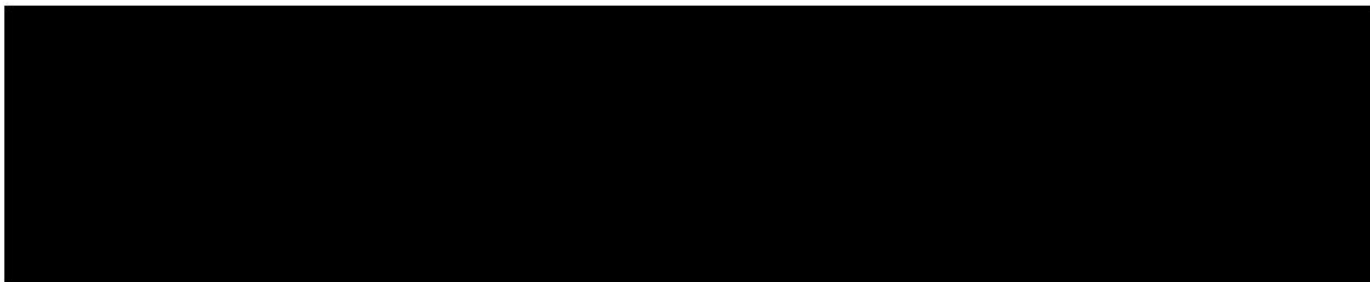
PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_005-Q002
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_005-Q002CONF
Request Date:	July 13, 2026
Requester DR No.:	005
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	July 27, 2026
PG&E Witness(es):	Angelia Vega

QUESTION 002

Refer to workpaper "08. ERRA_2027_Forecast_WP_PGE_20260515_Ch08_PCIA_CONF" and worksheet "CONF CTC and PCIA Interim SoD".
 When were the [REDACTED]

[REDACTED] What is the rationale behind that move? Did PG&E consult with any external stakeholders prior to that change in vintage? Did PG&E seek Commission approval prior to that change in vintage?

ANSWER 002

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_006-Q009
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_006-Q009
Request Date:	July 16, 2026
Requester DR No.:	006
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	July 31, 2026
PG&E Witness(es):	George Clavier

QUESTION 009

Refer to workpaper "08. ERRA_2027_Forecast_WP_PGE_202607XX_Ch08_PCIA_ERRATA_CONF", worksheet "CONF_CTC and PCIA_Interim SoD", row 268. Why is there no RA capacity value listed for project 33R551-H01, when the workpaper "05. ERRA_2027_Forecast_WP_PGE_20260515_Ch05_4-6_4-17_5-4_5-15_5-16_5-17_RA Open Position CONF" shows a capacity value in the peak hour of the months of March, April, June, July, August, September, and October on rows 3204-3215 of worksheet "Data"?

ANSWER 009

33R551-H01 is a solar generator that is part of hybrid solar/storage resource; 40S044-H01 is the associated battery energy storage system (BESS) unit. 33R551-H01 is an energy-only resource and therefore does not provide RA capacity that can be used for reliability compliance, hence the zero values in PGE_202607XX_Ch08_PCIA_ERRATA_CONF, worksheet "CONF_CTC and PCIA_Interim SoD. However, it is permitted to provide SoD RA charging supply for the associated battery. PG&E modeled a generation profile for the solar unit so that, when running the storage optimization algorithm, the generation from the solar generator would effectively provide charging sufficiency for the associated battery. The solar generation profile and battery operations are shown in 05. ERRA_2027_Forecast_WP_PGE_20260515_Ch05_4-6_4-17_5-4_5-15_5-16_5-17_RA Open Position CONF. The question identifies an issue pertaining to limitations on the SoD RA charging supply from the solar portion of the hybrid project as well as its inability to provide any RA supply that contributes towards meeting PG&E's bundled RA requirements, which ultimately has a small impact on the modeled monthly net open positions. In the Fall Update PG&E will correct this imprecision that resulted from including the full solar generation profile, which in some months extends beyond the charging hours and as a result the RA positions (lengths) calculated in ERRA_2027_Forecast_WP_PGE_20260515_Ch05_4-6_4-17_5-4_5-15_5-16_5-17_RA Open Position CONF were slightly overstated in some non-charging hours.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_007-Q001
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_007-Q001
Request Date:	July 23, 2026
Requester DR No.:	007
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 6, 2026
PG&E Witness(es):	Angelia Vega

QUESTION 001

Referring to the Public Errata Testimony, pg. 8-24 at Table 8-6, please provide detail of all changes to inputs or calculations that lead to the reduction in the PCIA indifference amount from \$656,676 to \$636,852.

ANSWER 001

The changes are summarized as follows:

1. Updated the fossil UOG units to vintage 2009, instead of UOG Legacy as described in PG&E's response to CalCCA's 5th data request, question 2. This update had no change to the PCIA indifference amount.
2. Removed the "Residual Capacity Sales" line item erroneously included in the worksheet of PCIA indifference calculation of the Initial Testimony as described in PG&E's supplemental response to CalCCA's 2nd data request, question 11. This update resulted in a change in the PCIA indifference amount from \$656,676 to \$636,852, as summarized below:

Residual Capacity Sales NQC removed	141.35 MW
RA Benchmark (\$/kW-Year)	\$138.36
Retained RA Value (\$'000)	\$19,558
RF&U @ 0.013604 (\$'000)	\$ 266
Retained RA Value with RF&U (\$'000)	\$19,824

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_007-Q003
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_007-Q003
Request Date:	July 23, 2026
Requester DR No.:	007
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 6, 2026
PG&E Witness(es):	Angelia Vega/Mark Coughlan

QUESTION 003

Refer to PG&E's response to DR CalCCA 1-6.

- a. Quantify the PCIA revenue requirement and rate impact of correcting the position for the balance of 2026 that drove generation volumes negative for the 2013 vintage. Provide all supporting workpapers and analysis in native, executable format.
- b. Confirm or deny, the position for the balance of 2026 that drove generation volumes negative for the 2013 vintage was corrected in the errata testimony filed July 17, 2026. If denied, when does PG&E plan to make this correction?

ANSWER 003

- a. In addition to the corrections described in the question, PG&E corrected the Resource Adequacy (RA) position in the July 17th Errata. The total revenue requirement and rate impact of the Portfolio Allocation Balancing Account (PABA) change are summarized in Attachment 01 to this data response.

As explained in PG&E's response to Question 6 of CalCCA's first data request, the April through August forecast will be replaced with recorded actuals in the Fall Update, and then with actuals through November as part of the 2026 year-end balances included in the AET.

- b. PG&E confirms that the position for the balance of 2026 described in the question, as well as PG&E's response to Question 6 of CalCCA's first data request was corrected in the errata testimony filed on July 17, 2026.

Table 12-2 (Change)
2026 FORECAST YEAR-END VINTAGE
(THOUSANDS OF DOLLARS)

Line No.	UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016
1	Recorded from January to March (a)								
2	Recorded Beginning Balance as of January	0	0	0	0	0	0	0	0
3	PCIA Customer Revenue	0	0	0	0	0	0	0	0
4	Portfolio Costs	0	0	0	0	0	0	0	0
5	Energy Value	0	0	0	0	0	0	0	0
6	RPS Value	0	0	0	0	0	0	0	0
7	RA Value	0	0	0	0	0	0	0	0
8	One Time Adjustments	0	0	0	0	0	0	0	0
9	Interest	0	0	0	0	0	0	0	0
10	Recorded March Balance	0	0	0	0	0	0	0	0
11	Forecast from April to December (b)								
12	PCIA Customer Revenue	0	0	0	0	0	0	0	0
13	Portfolio Costs	0	0	0	0	0	0	0	0
14	Energy Value	0	0	0	0	0	0	0	0
15	RPS Value	0	0	0	0	35,311	0	0	0
16	RA Value	(10,040)	(3,477)	(879)	(351)	(783)	(401)	(69)	(10)
17	One Time Adjustments	0	0	0	0	0	0	0	0
18	Interest	(99)	(49)	(14)	(6)	(10)	(51)	(1)	(0)
19	Forecast transactions from April to December	(10,139)	(3,526)	(893)	(357)	(793)	34,399	(50)	(70)
20	Forecast Year End Balance (c) = (a) + (b)								
21	Recorded Beginning Balance as of January	0	0	0	0	0	0	0	0
22	PCIA Customer Revenue	0	0	0	0	0	0	0	0
23	Portfolio Costs	0	0	0	0	0	0	0	0
24	Energy Value	0	0	0	0	0	0	0	0
25	RPS Value	0	0	0	0	35,311	0	0	0
26	RA Value	(10,040)	(3,477)	(879)	(351)	(783)	(401)	(69)	(10)
27	One Time Adjustments	0	0	0	0	0	0	0	0
28	Interest	(99)	(49)	(14)	(6)	(10)	(51)	(1)	(0)
29	Forecast Year End Balance before Transfers	(10,139)	(3,526)	(893)	(357)	(793)	34,399	(50)	(70)
30	Balance Transfers from ERRRA	0	0	0	0	0	0	0	0
31	Forecast Year End Balance after Balance Transfers	(10,139)	(3,526)	(893)	(357)	(793)	34,399	(50)	(70)
32	RF&U per Advice 5128-G/7727-E @ 0.013604	(454)	3,199	743	302	656	(250)	243	17
33	Forecast Year End Balance after Balance Transfers (Including RF&U)	(10,593)	(327)	(150)	(55)	(136)	34,148	193	(114)
34	Forecast System Sales by PCIA Vintage (kWh)		69,893,448,912	69,040,865,949	66,636,113,259	65,632,905,720	65,303,741,821	64,418,700,896	62,677,675,657
35	Rate Impact (\$/kWh)		(0.00016)	(0.00000)	(0.00000)	(0.00000)	0.00052	0.00000	(0.00000)

[illegible]

ERRA-2027-PGE-Forecast DR CalCCA 007-Q003-atc01.xlsx

Table 12-2 (ERRATA)
2026 FORECAST YEAR-END VINTAGED PABA BALANCES
(THOUSANDS OF DOLLARS)

Line No.		UOG Legacy	Vintage Subaccounts									
			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Recorded from January to March (a)											
2	Recorded Beginning Balance as of January	499,070	823,281	199,006	80,097	129,018	53,224	4,906	367	5,877	5,752	(47,564)
3	PCIA Customer Revenue	(144,973)	(304,470)	(60,689)	(18,936)	(27,168)	(4,848)	3,095	821	(876)	3,116	(2,753)
4	Portfolio Costs	209,226	229,724	65,041	19,726	28,736	9,699	5,501	3,745	399	1,820	(125)
5	Energy Value	(114,864)	(19,320)	(7,189)	(2,376)	(4,751)	(1,913)	(358)	(596)	(124)	(541)	0
6	RPS Value	(1,634)	(31,818)	(35,799)	(7,763)	(11,049)	(5,630)	(1,275)	(2,200)	(258)	(970)	0
7	RA Value	(53,439)	(62,145)	(10,585)	(5,402)	(6,401)	(5,204)	(380)	(314)	(74)	(1,712)	0
8	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413
9	Interest	6,574	9,086	2,144	896	1,465	577	83	4	66	84	(580)
10	Recorded March Balance	502,080	659,856	153,820	67,536	111,400	45,969	11,582	1,845	5,021	7,965	(50,608)
11	Forecast from April to December (b)											
12	PCIA Customer Revenue	(519,158)	(1,001,126)	(198,679)	(61,884)	(88,730)	(15,520)	10,252	2,743	(2,815)	10,707	(6,142)
13	Portfolio Costs	764,278	964,326	355,848	102,203	130,608	52,683	7,940	12,471	1,583	7,600	42
14	Energy Value	(487,692)	(137,137)	(72,030)	(32,587)	(41,866)	(23,831)	(4,234)	(6,941)	(882)	(4,156)	0
15	RPS Value	(12,538)	(185,596)	(163,447)	(44,045)	(48,029)	(34,566)	(6,428)	(10,037)	(1,348)	(6,127)	0
16	RA Value	(299,557)	(87,121)	(26,275)	(11,208)	(19,075)	(9,978)	(1,822)	(3,388)	(447)	(8,233)	0
17	One Time Adjustments	0	0	0	0	0	0	0	0	0	0	0
18	Interest	9,100	18,406	4,506	1,819	3,156	1,242	548	(15)	116	291	(2,026)
19	Forecast transactions from April to December	(545,565)	(428,248)	(100,077)	(45,703)	(63,936)	(29,970)	6,256	(5,166)	(3,793)	81	(8,125)
20	Forecast Year End Balance (c) = (a) + (b)											
21	Recorded Beginning Balance as of January	499,070	823,281	199,006	80,097	129,018	53,224	4,906	367	5,877	5,752	(47,564)
22	PCIA Customer Revenue	(664,131)	(1,305,597)	(259,368)	(80,820)	(115,898)	(20,368)	13,347	3,564	(3,691)	13,823	(8,895)
23	Portfolio Costs	973,504	1,194,050	420,890	121,928	159,344	62,381	13,441	16,216	1,982	9,419	(83)
24	Energy Value	(602,555)	(156,457)	(79,220)	(34,963)	(46,617)	(25,743)	(4,591)	(7,536)	(1,006)	(4,697)	0
25	RPS Value	(14,172)	(217,413)	(199,246)	(51,807)	(59,077)	(40,196)	(7,703)	(12,236)	(1,606)	(7,098)	0
26	RA Value	(352,996)	(149,266)	(36,860)	(16,610)	(25,476)	(15,182)	(2,202)	(3,702)	(521)	(9,946)	0
27	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413
28	Interest	15,674	27,492	6,650	2,716	4,621	1,819	631	(11)	183	375	(2,605)
29	Forecast Year End Balance before Transfers	(43,485)	231,609	53,743	21,833	47,464	15,999	17,839	(3,321)	1,229	8,046	(58,734)
30	Balance Transfers from ERRA	0	0	0	0	0	0	0	0	0	0	0
31	Forecast Year End Balance after Balance Transfers	(43,485)	231,609	53,743	21,833	47,464	15,999	17,839	(3,321)	1,229	8,046	(58,734)
32	RF&U per Advice 5128-G/7727-E @ 0.013604	(592)	3,151	731	297	646	218	243	(45)	17	109	(799)
33	Forecast Year End Balance after Balance Transfers (Including RF&U)	(44,076)	234,759	54,474	22,130	48,109	16,217	18,081	(3,366)	1,245	8,156	(59,533)

Totals may not add due to rounding

2019	2020	2021	2022	2023	2024	2025	2026	Total
45,002	(29,675)	507,967	28,076	18,060	(100,681)	48,708	0	2,270,492
(3,903)	6,281	(101,728)	(644)	(6,513)	16,170	303,132	0	(344,885)
12,735	(876)	45,790	9	(14)	25	27	(7)	631,180
0	0	(163)	0	(10)	0	0	0	(152,203)
0	0	(4,726)	0	(60)	0	(23,232)	23,232	(103,180)
(10,308)	0	(31,796)	0	(2,562)	(39)	(180)	0	(190,543)
407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
559	(328)	5,776	346	175	(1,128)	(12,874)	142	13,067
44,492	(24,112)	421,612	28,271	9,076	(85,591)	(1,160,933)	23,366	772,649
(11,853)	22,522	(357,831)	(1,640)	(22,109)	63,231	1,220,960	0	(957,073)
33,214	0	108,852	(0)	14,402	363	524	133	2,557,070
0	0	(2,537)	0	(395)	(145)	(208)	(110)	(814,751)
0	(445)	(30,430)	0	(874)	(324)	(440)	288	(544,386)
(51,443)	0	(143,660)	0	(10,821)	(65)	(281)	(370)	(673,744)
0	0	0	0	0	0	0	0	0
1,103	(500)	7,964	1,039	(42)	(2,080)	(21,511)	877	23,996
(28,979)	21,577	(417,642)	(601)	(19,840)	60,981	1,199,043	818	(408,888)
45,002	(29,675)	507,967	28,076	18,060	(100,681)	48,708	0	2,270,492
(15,756)	28,803	(459,559)	(2,284)	(28,622)	79,402	1,524,092	0	(1,301,958)
45,949	(876)	154,643	9	14,388	387	551	126	3,188,251
0	0	(2,700)	0	(405)	(145)	(208)	(110)	(966,954)
0	(445)	(35,156)	0	(934)	(324)	(23,672)	23,519	(647,566)
(61,751)	0	(175,456)	0	(13,383)	(104)	(461)	(370)	(864,287)
407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
1,662	(827)	13,740	1,385	133	(3,208)	(34,386)	1,019	37,063
15,513	(2,536)	3,970	27,671	(10,763)	(24,611)	38,110	24,185	363,761
0	0	0	0	0	0	0	(187,921)	(187,921)
15,513	(2,536)	3,970	27,671	(10,763)	(24,611)	38,110	(163,736)	175,840
211	(34)	54	376	(146)	(335)	518	(2,227)	2,392
15,724	(2,570)	4,024	28,047	(10,910)	(24,945)	38,629	(165,964)	178,232

(0)

Table 12-2 (May Filed)
2026 FORECAST YEAR-END VINTAGED PABA BALANCES
(THOUSANDS OF DOLLARS)

Line No.		UOG Legacy	Vintage Subaccounts									
			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Recorded from January to March (a)											
2	Recorded Beginning Balance as of January	499,070	823,281	199,006	80,097	129,018	53,224	4,906	367	5,877	5,752	(47,564)
3	PCIA Customer Revenue	(144,973)	(304,470)	(60,689)	(18,936)	(27,168)	(4,848)	3,095	821	(876)	3,116	(2,753)
4	Portfolio Costs	209,226	229,724	65,041	19,726	28,736	9,699	5,501	3,745	399	1,820	(125)
5	Energy Value	(114,864)	(19,320)	(7,189)	(2,376)	(4,751)	(1,913)	(358)	(596)	(124)	(541)	0
6	RPS Value	(1,634)	(31,818)	(35,799)	(7,763)	(11,049)	(5,630)	(1,275)	(2,200)	(258)	(970)	0
7	RA Value	(53,439)	(62,145)	(10,585)	(5,402)	(6,401)	(5,204)	(380)	(314)	(74)	(1,712)	0
8	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413
9	Interest	6,574	9,086	2,144	896	1,465	577	83	4	66	84	(580)
10	Recorded March Balance	502,080	659,856	153,820	67,536	111,400	45,969	11,582	1,845	5,021	7,965	(50,608)
11	Forecast from April to December (b)											
12	PCIA Customer Revenue	(519,158)	(1,001,126)	(198,679)	(61,884)	(88,730)	(15,520)	10,252	2,743	(2,815)	10,707	(6,142)
13	Portfolio Costs	764,278	964,326	355,848	102,203	130,608	52,683	7,940	12,471	1,583	7,600	42
14	Energy Value	(487,692)	(137,137)	(72,030)	(32,587)	(41,866)	(23,831)	(4,234)	(6,941)	(882)	(4,156)	0
15	RPS Value	(12,538)	(185,596)	(163,447)	(44,045)	(48,029)	(69,878)	(6,428)	(10,037)	(1,348)	(6,127)	0
16	RA Value	(289,517)	(83,644)	(25,396)	(10,857)	(18,292)	(9,577)	(1,773)	(3,319)	(437)	(7,991)	0
17	One Time Adjustments	0	0	0	0	0	0	0	0	0	0	0
18	Interest	9,200	18,455	4,521	1,825	3,166	1,753	549	(14)	117	294	(2,026)
19	Forecast transactions from April to December	(535,426)	(424,722)	(99,184)	(45,346)	(63,143)	(64,369)	6,306	(5,096)	(3,783)	326	(8,125)
20	Forecast Year End Balance (c) = (a) + (b)											
21	Recorded Beginning Balance as of January	499,070	823,281	199,006	80,097	129,018	53,224	4,906	367	5,877	5,752	(47,564)
22	PCIA Customer Revenue	(664,131)	(1,305,597)	(259,368)	(80,820)	(115,898)	(20,368)	13,347	3,564	(3,691)	13,823	(8,895)
23	Portfolio Costs	973,504	1,194,050	420,890	121,928	159,344	62,381	13,441	16,216	1,982	9,419	(83)
24	Energy Value	(602,555)	(156,457)	(79,220)	(34,963)	(46,617)	(25,743)	(4,591)	(7,536)	(1,006)	(4,697)	0
25	RPS Value	(14,172)	(217,413)	(199,246)	(51,807)	(59,077)	(75,507)	(7,703)	(12,236)	(1,606)	(7,098)	0
26	RA Value	(342,956)	(145,789)	(35,981)	(16,259)	(24,694)	(14,781)	(2,153)	(3,633)	(511)	(9,703)	0
27	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413
28	Interest	15,773	27,541	6,664	2,721	4,631	2,330	632	(10)	183	378	(2,605)
29	Forecast Year End Balance before Transfers	(33,346)	235,135	54,636	22,190	48,256	(18,399)	17,889	(3,251)	1,239	8,291	(58,734)
30	Balance Transfers from ERRRA	0	0	0	0	0	0	0	0	0	0	0
31	Forecast Year End Balance after Balance Transfers	(33,346)	235,135	54,636	22,190	48,256	(18,399)	17,889	(3,251)	1,239	8,291	(58,734)
32	RF&U per Advice 5128-G/7727-E @ 0.013604	(454)	3,199	743	302	656	(250)	243	(44)	17	113	(799)
33	Forecast Year End Balance after Balance Transfers (Including RF&U)	(33,799)	238,334	55,380	22,492	48,913	(18,650)	18,132	(3,295)	1,256	8,404	(59,533)

Totals may not add due to rounding

2019	2020	2021	2022	2023	2024	2025	2026	Total
45,002	(29,675)	507,967	28,076	18,060	(100,681)	48,708	0	2,270,492
(3,903)	6,281	(101,728)	(644)	(6,513)	16,170	303,132	0	(344,885)
12,735	(876)	45,790	9	(14)	25	27	(7)	631,180
0	0	(163)	0	(10)	0	0	0	(152,203)
0	0	(4,726)	0	(60)	0	(23,232)	23,232	(103,180)
(10,308)	0	(31,796)	0	(2,562)	(39)	(180)	0	(190,543)
407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
559	(328)	5,776	346	175	(1,128)	(12,874)	142	13,067
44,492	(24,112)	421,612	28,271	9,076	(85,591)	(1,160,933)	23,366	772,649
(11,853)	22,522	(357,831)	(1,640)	(22,109)	63,231	1,220,960	0	(957,073)
33,214	0	108,852	(0)	14,402	363	524	133	2,557,070
0	0	(2,537)	0	(395)	(145)	(208)	(110)	(814,751)
0	(445)	(30,430)	0	(874)	(324)	(440)	288	(579,697)
(50,200)	0	(140,018)	0	(10,474)	(62)	(265)	(346)	(652,168)
0	0	0	0	0	0	0	0	0
1,114	(500)	7,996	1,039	(39)	(2,080)	(21,511)	878	24,737
(27,725)	21,577	(413,968)	(601)	(19,490)	60,984	1,199,060	843	(421,881)
45,002	(29,675)	507,967	28,076	18,060	(100,681)	48,708	0	2,270,492
(15,756)	28,803	(459,559)	(2,284)	(28,622)	79,402	1,524,092	0	(1,301,958)
45,949	(876)	154,643	9	14,388	387	551	126	3,188,251
0	0	(2,700)	0	(405)	(145)	(208)	(110)	(966,954)
0	(445)	(35,156)	0	(934)	(324)	(23,672)	23,519	(682,877)
(60,508)	0	(171,814)	0	(13,036)	(101)	(445)	(346)	(842,711)
407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
1,673	(827)	13,772	1,385	136	(3,208)	(34,386)	1,020	37,804
16,767	(2,536)	7,644	27,671	(10,414)	(24,608)	38,126	24,209	350,768
0	0	0	0	0	0	0	(174,928)	(174,928)
16,767	(2,536)	7,644	27,671	(10,414)	(24,608)	38,126	(150,719)	175,840
228	(34)	104	376	(142)	(335)	519	(2,050)	2,392
16,996	(2,570)	7,748	28,047	(10,555)	(24,942)	38,645	(152,769)	178,232

(0)

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_007-Q004
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_007-Q004
Request Date:	July 23, 2026
Requester DR No.:	007
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 6, 2026
PG&E Witness(es):	Bill Reinwald

QUESTION 004

Refer to the Public Errata Testimony, page 8-15, Table 8-2, lines 11-12, col. (G).

- a. Please provide the volume (MWh) by date (month and year) that the total 2023 and 2024 unsold RPS must be retired in WREGIS.
- b. What is the total volume of unsold RPS that has been retired in WREGIS since the initial filing of the 2027 ERRA Forecast in May 2026?
- c. What total volume of unsold RPS has been sold since the initial filing of the 2027 ERRA Forecast in May 2026?

ANSWER 004

- a. The following table shows the quantity of RECs, and the last day to retire each vintage to meet the 36-month deadline, of all Unsold VAMO RECs as of 7/30/2026.

Vintage	Sum of Quantity (RECs)	Last date to retire
1/1/2023	311,556	12/31/2025
2/1/2023	323,655	1/31/2026
3/1/2023	331,920	2/28/2026
4/1/2023	424,407	3/31/2026
5/1/2023	431,981	4/30/2026
6/1/2023	397,691	5/31/2026
7/1/2023	410,336	6/30/2026
8/1/2023	321,512	7/31/2026
9/1/2023	145,852	8/31/2026
10/1/2023	128,630	9/30/2026
11/1/2023	115,382	10/31/2026
12/1/2023	65,251	11/30/2026

Vintage	Sum of Quantity (RECs)	Last date to retire
1/1/2024	36,969	12/31/2026
2/1/2024	29,984	1/31/2027
3/1/2024	33,304	2/28/2027
4/1/2024	43,737	3/31/2027
5/1/2024	35,683	4/30/2027
6/1/2024	37,389	5/31/2027
7/1/2024	29,811	6/30/2027
8/1/2024	28,754	7/31/2027
9/1/2024	28,398	8/31/2027
10/1/2024	41,352	9/30/2027
11/1/2024	32,156	10/31/2027
12/1/2024	35,348	11/30/2027
Grand Total	3,821,058	

b. PG&E has retired all unsold RECs from Jan-August 2023. PG&E has also retired a portion of unsold RECs from Sept-Dec 2023. The total volume of retired unsold RECs as of 8/6/2026 is 3,135,126.

c. As of this response, PG&E has not sold any Unsold VAMO RECs.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q004
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q004
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Various

QUESTION 004

See pages 2-11 to 2-13 of PG&E's Prepared Direct Testimony, where PG&E describes its data center load forecast. Please describe in detail how PG&E assigns a) historic and b) forecasted data center load to PCIA vintages for the purposes of PCIA ratemaking in this 2027 ERRA Forecast Application. To the extent either historic or forecasted data center load is not assigned to any PCIA vintage, and is instead reflected in some other cost recovery mechanism, please identify that cost recovery mechanism and explain why data center load is reflected in that mechanism.

ANSWER 004

A discussion of PG&E's design of PCIA rates is included on pages 13-4 and 13-5 of PG&E's Prepared Testimony for the 2027 ERRA Forecast May Application.

Departed Load customers are assigned to a PCIA vintage based on the year that they departed PG&E's bundled service, with July 1 being the date that a new yearly vintage comes into effect. So, for example, a customer who departed PG&E's service on June 30, 2020 would belong to PCIA Vintage 2019 whereas a customer who departed PG&E's service on July 1, 2020 would belong to PCIA Vintage 2020. Customers who depart PG&E's service on or after July 1, 2027 would be assigned to PCIA Vintage 2027. PG&E's PCIA Rate Calculation workpapers do not include a forecast of customers who are forecasted to depart bundled service during this timeframe, which is why the number in cell X11 in the tab "Base PCIA Rate Design" is equal to the forecasted system Bundled sales of 22,918,685,439 kWh – PG&E customers who would potentially depart PG&E's bundled service during the 2027 test year are treated as Bundled customers for the purpose of PCIA rate design, and their forecasted load is included in the Bundled sales total.

Concerning cost recovery for historic or forecasted data center load, departed load customers would pay the PCIA rate applicable to their vintage and customer class. Data center customers who have not departed PG&E's service would be assigned the bundled generation and PCIA rate of their applicable rate schedule.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q009
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q009
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 009

Please see PG&E's Supplemental Testimony at page 3, lines 25-27, where it states

“PG&E now models data centers being energized based on a specific month, rather than assuming that energizations and ramping are effectively spread uniformly through the calendar year.”

- a. Please explain how PG&E determines or models the month of data center energization.
- b. Does PG&E's process for determining the month of data center energization involve discussion with the CCA that will serve the relevant data center load? Please explain in detail.
- c. Does PG&E's process for determining the month of data center energization involve any discussions with the municipality or authority having jurisdiction for the area in which the data center will be located? Please explain in detail.

ANSWER 009

- a. PG&E's forecast uses ramp schedule and projected energization date data from the PG&E teams that manage the data center projects through the application queue. Projected energization date estimates are based on PG&E's understanding of the projects' status within the planning and construction process. If projected energization date is not available, June 30th of the first year of a project's ramp schedule with capacity is assumed.
- b. No. The projected energization date data comes from conversations with the prospective customers. That is, these projected energization dates are developed in collaboration with data center developers themselves.
- c. No. The projected energization date data comes from conversations with the prospective customers. That is, these projected energization dates are developed in collaboration with data center developers themselves.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q010
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q010
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 010

Please see PG&E's Supplemental Testimony at page 3, lines 28-29, where it states

"PG&E now models data centers ramping over a 12-month period rather than by the end of the calendar year."

- a. Why does PG&E model data centers ramping over a 12-month period?
- b. Please indicate the number of instances in which a data center served by PG&E has completed its load ramp over a period less than or equal to 12 months.
- c. Does PG&E receive estimated ramping periods from the data centers in its application queue? If the answer is anything other than an unequivocal no, please explain why PG&E's load forecast does not reflect those estimates.
- d. Is PG&E aware of data centers either currently or previously in its application queue that anticipate ramping periods longer than 12 months?
- e. Confirm PG&E permits data centers to ramp over a period longer than 12 months.

ANSWER 010

- a. PG&E decided to model incremental capacity coming online over a twelve-month ramp given that we now use month-specific project energization dates (see PG&E's Supplemental Testimony page 3, lines 19-27). We believe this more granular modeling is better than the prior methodology. See the example outlined in the Supplemental Testimony (page 3, line 32 to page 4, line 4) for an illustrative example comparing the two methodologies.
- b. This analysis is not available.
- c. The ramp schedules used for the forecast are provided by PG&E internal teams that manage the data center projects through the application queue – as mentioned in PG&E's response to question 9 of this data request – are limited to annual granularity. We do not have information on monthly ramp schedules.

- d. Most data centers in PG&E's application queue anticipate total ramping periods longer than one year. Note that the twelve-month ramping period assumption presented in the Supplemental Testimony does not assume that a project will ramp to its full capacity in twelve months. See PG&E's response to question 11 of this data request for further explanation.
- e. PG&E is not involved in determining data centers' minimum ramp rates.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q014
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q014
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 014

Please see page 4, lines 11-13 of PG&E's Supplemental Testimony, where it states:

“For the Fall Update, PG&E anticipates revising these assumptions based on analysis of new large data centers’ recorded performance.”

- a. Please provide the referenced analysis.
- b. If the referenced analysis has not been conducted, please explain in detail what that analysis will entail, including inputs, assumptions, modeling methodology and software, and anticipated outputs.
- c. Please explain what PG&E means by “new large data centers’ recorded performance” in detail. In your answer, please identify 1) the period over which the “recorded performance” is, 2) the number of large data centers on which PG&E’s analysis is or will be based, 3) the capacity threshold or other criteria PG&E uses to define a “large data center”, and 4) the total MW (of contract capacity) corresponding to the large data centers on which PG&E’s analysis is or will be based.

ANSWER 014

- a. PG&E objects to providing this data on the grounds that it could reveal confidential customer information.
- b. n/a – The analysis has been conducted.
- c. PG&E has developed a database to track the load of known data centers on its system.
 1. The database has monthly usage data back to 2010 and hourly usage data back to 2016. However, for the purposes of this question, the new capacity utilization assumption was based on January-August 2025 data, while the new load factor assumption was based on January-November 2025 data.

2. The capacity utilization assumption was based on analysis of six large data centers. The load factor assumption was based on analysis of thirty-nine large data centers.
3. "Large" in this case indicates data centers exhibiting loads of at least 1 MW.
4. PG&E objects to providing this data on the grounds that it could reveal confidential customer information.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q016
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q016
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 016

Please see page 2-11 of PG&E's Prepared Direct Testimony, where PG&E states:

“The forecast assumes no offsetting impacts from on-site generation under normal operating conditions.”

- a. Please explain why PG&E's forecast assumes no offsetting impacts from on-site generation under normal operating conditions.
- b. Does PG&E's forecasting assumption remain intact even in situations where it is aware of a customer that intends to install, or has already installed, behind- or front-of-the-meter, on-site generation other than emergency generators (i.e., solar, storage, or natural gas generators supplying the customer's non-emergency needs)? If the answer is anything other than an unequivocal yes, please explain in detail.

ANSWER 016

- a. In the absence of information from data center customers regarding potential on-site generation, PG&E has not made speculative assumptions about its future use by data centers.
- b. Yes, the assumption remains intact. See PG&E's response to part a of this question for why PG&E does not forecast non-emergency on-site generation.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q017
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q017
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 017

See page 2-11 of PG&E's prepared direct testimony, lines 29-33, where PG&E states it applies a 90 percent materialization rate to each project's capacity ramp schedule.

- a. Please provide PG&E's basis for applying a 90 percent materialization rate, as opposed to any other level.
- b. Please also confirm that this aspect of PG&E's data center load forecasting methodology will remain intact in PG&E's Fall Update and is not modified by the changes described in PG&E's Supplemental Testimony. If not confirmed, please explain how this aspect of PG&E's data center load forecasting methodology will change in the Fall Update.

ANSWER 017

- a. PG&E's Prepared Testimony of its 2027 ERRA Forecast May15, 2026 filing, page 2-11, lines 29-33, states that the basis for this is subject matter expert's judgment, reflecting some level of uncertainty that projects do indeed materialize.
- b. PG&E objects to this question as inconsistent with the structured nature of the ERRA Forecast proceeding. PG&E will address any changes to the data center forecasting methodology in the Fall Update Testimony.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q018
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q018
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 018

See page 2-12 of PG&E's prepared direct testimony, lines 1-2, where PG&E states it applies a capacity utilization rate of 85 percent to the capacity forecast in order to forecast annual peak demand for its data centers.

- a. Please provide PG&E's basis for applying a 85 percent capacity utilization rate, as opposed to any other level.
- b. Please also confirm that this aspect of PG&E's data center load forecasting methodology will remain intact in PG&E's Fall Update and is not modified by the changes described in PG&E's Supplemental Testimony. If not confirmed, please explain how this aspect of PG&E's data center load forecasting methodology will change in the Fall Update.

ANSWER 018

- a. As stated on page 2-12, lines 1-5 of PG&E's Prepared Testimony of its 2027 ERRA Forecast May Filing, this capacity utilization rate assumption is based on PG&E subject matter experts' judgment and reflects PG&E's expectation that the new generation of data centers will exhibit high capacity utilization to maximize data center owners' use of the facility.
- b. PG&E objects to this question as inconsistent with the structured nature of the ERRA Forecast proceeding. PG&E will address any changes to the data center forecasting methodology in the Fall Update Testimony.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q019
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q019
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Daniel Nelli

QUESTION 019

See page 2-12 of PG&E's prepared direct testimony, lines 15-17, where PG&E states it applies an 88 percent load factor assumption to convert peak demand for both existing and new large data centers to annual sales.

- a. Please provide PG&E's basis for applying an 88 percent load factor assumption, as opposed to any other level.
- b. Please also confirm that this aspect of PG&E's data center load forecasting methodology will remain intact in PG&E's Fall Update and is not modified by the changes described in PG&E's Supplemental Testimony. If not confirmed, please explain how this aspect of PG&E's data center load forecasting methodology will change in the Fall Update.

ANSWER 019

- a. PG&E's Prepared Testimony of its 2027 ERRA Forecast May Filing states that the basis for this is subject matter expert judgment; refer to page 2-12, lines 17-18.
- b. PG&E objects to this question as inconsistent with the structured nature of the ERRA Forecast proceeding. PG&E will address any changes to the data center forecasting methodology in the Fall Update Testimony.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_008-Q020
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_008-Q020
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 14, 2026
PG&E Witness(es):	Jorge Meraz

QUESTION 020

Please see page 2-19 to 2-20 of PG&E's Prepared Direct Testimony, in which it discusses meet-and-confer discussions between PG&E and CCAs with expected data center load in 2027. If those discussions do not result in alignment between PG&E's and each CCA's respective data center load forecast by the time PG&E files its Annual Electric True-up (AET) for 2027, how will PG&E resolve that misalignment? Which data center load forecast will PG&E use for the purposes of developing 2027 rates in this proceeding?

ANSWER 020

If there is misalignment between PG&E's and a CCA's ERRA Spring forecast (aggregate load forecast, inclusive of data center load), PG&E and the CCAs work towards alignment through the ERRA Fall Update meet and confer (currently underway). If discussions do not result in alignment, PG&E will use its internal load forecast (for the ERRA Fall Update) for the CCAs for which there is disagreement and continue discussions during the following ERRA cycle. PG&E objects to questions about the AET as irrelevant to this ERRA Forecast proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2027 Forecast
Application 26-05-007
Data Response

PG&E Data Request No.:	CalCCA_009-Q007
PG&E File Name:	ERRA-2027-PGE-Forecast_DR_CalCCA_009-Q007
Request Date:	July 31, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 18, 2026
PG&E Witness(es):	George Clavier

QUESTION 007

Does PG&E's PCIA-eligible portfolio include any long-duration storage resources?

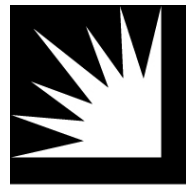
ANSWER 007

PG&E has no PCIA-eligible long-duration storage (non-pumped storage) resources that are expected to deliver in 2027.

Attachment RAM-4:

**Excerpted Public Testimony from SCE Energy Resource Recovery Account (ERRA) 2027
Forecast**

Application No.:	<u>A.26-05-006</u>	
Exhibit No.:	<u>SCE-01</u>	
Witnesses:	T. Cameron	K. Seeto
	J. Cui	E. Salazar
	L. Dalusong	T. Salisbury
	L. Gaillac	M. Sayed
	E. Lee	D. Spencer
	R. Liang	A. Wong



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(U 338-E)

Energy Resource Recovery Account (ERRA)
2027 Forecast of Operations

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 15, 2026

1 value of that portfolio (defined as the forecast output of the resources in the generation portfolio
2 multiplied by the energy, RPS, and RA MPBs).¹⁸⁵

3 In D.08-09-012, the Commission adopted the practice of vintaging the utility's generation
4 portfolio to ensure that Departing Load customers are held responsible only for generation procured
5 prior to the date of their departure from bundled service. Accordingly, SCE calculated Indifference
6 Amounts for each "vintage year" based on the generation resources that were committed in each
7 calendar year.¹⁸⁶ These Indifference Amounts represent the revenue requirements in each vintaged sub-
8 account of the PABA.

9 The vintaged PABA revenue requirements are then allocated to rate groups using generation
10 revenue allocators approved in SCE's GRC Phase 2 proceeding normalized to account for each rate
11 group's kWh sales forecast by vintage and divided by forecast sales by vintage (also referred to as
12 billing determinants) to set the final CTC and PCIA rates. The CTC rate is used to recover the above-
13 market costs of pre-restructuring resources such as eligible QFs and is the same for all vintages. The
14 PCIA rates are used to recover the above-market costs of all non-CTC-eligible resources (e.g., UOG and
15 "New-World" generation resources as authorized in D.04-12-048 and modified by D.18-10-019) and
16 vary by vintage based on the generation resources included in that vintage.¹⁸⁷

17 **B. RA SOD Framework**

18 In D.23-04-010, the Commission affirmed that it intended to move forward with SOD
19 implementation in 2025. On June 20, 2024, the Commission approved D.24-06-004, which confirmed
20 the start of the SOD framework in 2025. On August 16, 2024, SCE served Supplemental Testimony in
21 its 2025 ERRA Forecast proceeding to detail its proposed interim solution for implementing SOD in its
22 PCIA ratemaking, which SCE has also applied in this Application. In the 2025 ERRA Forecast (A.24-

¹⁸⁵ The MPBs are now referred to as the Energy Index, RPS Adder and RA Adders.

¹⁸⁶ Pursuant to D.08-09-012, customers are assigned a vintage based on the date of their departure. If they departed on or before June 30 of a given year, they are assigned to the prior year's vintage. Alternatively, if they departed on or after July 1 of a given year, they are assigned that year's vintage.

¹⁸⁷ As described in D.06-07-030, the CTC and PCIA are set such that the sum of the two equals the Indifference Amount.

05-007), the Commission found SCE’s proposed methodology to be a reasonable execution of Commission guidance given to account for how RA is counted for compliance purposes.¹⁸⁸ This methodology was also approved in SCE’s 2026 ERRRA Forecast (A.25-05-008).¹⁸⁹

The SOD framework transitions the CPUC’s RA program from a single NQC check in the peak hour of each month to a capacity check in every hour of the “worst day” (24 total) for each month. The SOD framework also requires charging sufficiency for storage resources. These changes necessitate a shift in how the value of RA is calculated, moving away from the traditional NQC-based method to a more dynamic and granular approach that aligns with the new SOD rules.

To represent SCE’s RA position as a single monthly number, SCE converts its hourly position into a monthly position by taking an average of its hourly optimized supply and creating a “baseload equivalent” position. In addition to this baseload equivalent position, SCE accounts for its excess energy storage quantities to better represent its procurement need, especially for energy sufficiency to charge these energy storage resources. The following assumptions were used for determining price and quantity:

1. Price

SCE does not assume any changes to the price, or the RA MPB, and is using the Commission-issued RA MPB. Traditionally, the RA price has been indicative of 1 kW-month of reliability, measured based on the net-peak hour. This means that the price was reflective of the capacity to provide reliable power during the period of highest demand. However, under the SOD framework, the RA price would reflect the price for 1 kW-month of reliability but now measured over an entire 24-hour period. This change recognizes the fact that reliability is no longer only about meeting the peak demand but ensuring reliable power during the 24-hour period of demand.

Moreover, the requirement for RA compliance in each hour of the day implies the possibility of an hourly structured RA price. This is because higher RA requirements in certain hours

¹⁸⁸ See D.24-12-039, p. 75.

¹⁸⁹ See D.25-12-028, p. 119.

can lead to higher RA price in those hours. The relevance of varying requirements within hours is somewhat mitigated by storage. Storage reshapes the RA requirement curve by absorbing capacity for charging during the long RA hours, thereby increasing requirements, and providing capacity during short RA hours, thereby decreasing requirements.

2. Quantity

As discussed above, under the “single slice” regime, the quantity of reliability has been measured as the NQC, which represents the capacity a resource can offer to the grid during the single peak hour of each month. Under the SOD framework, a resource’s RA quantity must reflect the reliable capacity provided by the resource over a full 24-hour period. SCE is representing the RA quantity of different resource types based on a “baseload equivalent” RA quantity and to report resources’ NQC values in the PCIA workpaper based on the optimized amount the resource contributes towards SCE’s compliance requirements. The baseload-equivalent RA quantity normalized by the capacity of the resource signifies the effective contribution of the resource towards meeting the SOD requirement. This measure can be referred to as the “SOD RA Effectiveness Factor.” Below is a description of the methodology to estimate RA quantity by resource type:

a) Baseload Resources

For baseload resources, which deliver consistent output throughout the day, their RA quantity remains unchanged when transitioned to the SOD framework. The SOD RA Effectiveness Factor for these resources can be up to 100 percent of their capacity, although this may be reduced for de-rates and operational constraints as reflected in their NQC.

b) Intermittent Resources

For intermittent resources (*e.g.*, wind, solar), the baseload equivalent can be estimated by the average of their hourly exceedance values output. In the SOD framework, the RA counting methodology for intermittent resources like wind and solar has transitioned to an exceedance-based approach, moving away from the traditional ELCC-based approach. The ELCC provides a single value for a month, whereas the exceedance value, available in the Master Resource Database (MRD) published by the CPUC, offers a value for each hour of the day for a specific month. Just like ELCC,

the exceedance value also varies depending on the region and technology. By taking the average of the exceedance value over a 24-hour period, the SOD RA Effectiveness Factor for intermittent resources can be determined. With the use of energy storage, the excess power generated by intermittent resources during their peak times can be stored and then discharged when their generation drops off. This effectively flattens the power generation profile over a 24-hour period, making it equivalent to a single capacity number that is constant throughout the day.

c) Stand-alone Storage

In the SOD framework, storage resources are not assigned specific pre-determined hourly quantities for the hourly capacity determination. Instead, storage resources are optimized to address RA shortfalls during any hour of the day. Furthermore, the CPUC's QC methodology for energy storage has not changed. It is still based on the capacity (MW) level at which the storage resource is capable of discharging for four or more consecutive hours. Under the previous RA framework, storage resources with a duration of four hours or more are deemed equivalent to baseload for RA counting, underscoring their ability to provide capacity during the peak period. Therefore, their RA quantity can still be based on their NQC value. However, the SOD rules introduced an additional requirement: storage resources can only be counted towards RA if there is sufficient charging capacity. The combination of storage resources and the charging RA capacity provides a solution equivalent to baseload. Therefore, the effective contribution from storage is calculated as the storage NQC minus the RA capacity needed for charging.

The RA capacity needed for charging considers round trip efficiency (RTE) and duration of the storage resource. A storage resource with poor RTE would require more RA charging capacity and, as a result, would have a lesser effective RA contribution and vice versa. As a result, the formula for calculating the RA quantity of storage resources in the SOD framework can be stated as follows: $NQC - NQC \times 4 / 24 / RTE$.

d) Hybrid/Co-located Storage

The total RA quantity of hybrid or co-located resources is the sum of the renewables and storage components limited by the Point-of-Interconnection (POI) limit. The RA

1 quantity of the renewable component is determined based on the average of the exceedance values as
2 discussed above. The RA quantity of the storage component is estimated based on the previously
3 described formulation.

4 For energy storage resources that are restricted from charging from the grid, the
5 storage capacity can be adjusted to match the chargeable capacity from the renewable component. In
6 accordance with D.24-06-004, there is no reduction in the QC value of the renewable component.

7 In the case of energy-only (EO) resources, the storage is credited for charging
8 capacity from the renewable component. The EO component remains bundled with the storage system.
9 In accordance with OP 9 of D.24-06-004, an EO resource can meet the storage charging sufficiency
10 requirement if it exclusively charges a paired storage system, regardless of whether the paired storage
11 can also charge from the grid. Similarly, in the case of a co-located resource that is partially or fully
12 deliverable, the variable energy component (if contracted by SCE) is counted toward RA and off-site
13 charging sufficiency requirements up to its deliverable capacity, provided the combined generation and
14 storage output does not exceed the point of interconnection in the same hour, as set forth in OP 10 of
15 D.25-06-048.

16 An adjustment was required to reduce the RA capacity for MCAM contracts in
17 PCIA vintage 2019 and increase the RA capacity of solar resources in PCIA vintages 2011, 2014, and
18 2015 to more accurately depict the value of these co-located resources.

19 SCE's generic RA procurement costs and excess sales revenues are based on its
20 position under the SOD framework. To create its position under the SOD framework, SCE utilized its
21 internal optimization tool and the MRD from the Commission to create hourly 2027 profiles for
22 baseload resources. Additionally, the tool was used to optimize SCE's energy storage portfolio to fill
23 the remaining open position. SCE's internal tool provides the total 24-hour profile of the unit.

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



FILED

09/02/26

04:59 PM

R2502005

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 COMMENTS
ON THE PROPOSED DECISION RESOLVING TRACK TWO ISSUES**

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September 2, 2026

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SUMMARY OF RECOMMENDATIONS¹

The PD should be rejected and replaced with an Alternate Decision, as set forth in Appendix A, because:

- × The PD violates section 366.2(g) by failing to fulfill the Commission’s ongoing statutory obligation to reduce the cost obligation of Later Departed Customers by the value of benefits “that remain” with bundled customers; (
- × The PD violates section 1705’s requirement that Commission decisions include findings on “all issues material to the order or decision,” by failing to make any findings on how assigning the entire compliance value to current bundled customers while providing zero value to Later Departed Customers for the Pre-2019 Banked RECs satisfies the indifference mandates; (
- × The PD’s finding that CalCCA’s position is untimely for failure to seek rehearing of D.11-12-018 and D.19-10-001 is legally erroneous because: (
 - Section 1731(b) allows rehearing only with “respect to matters determined in the action or proceeding”; and (
 - Neither Decision includes any discussion or resolution of whether Later Departed Customers would be entitled to value when current bundled customers use the RECs; (
- × The PD commits legal error by finding that laches bars CalCCA’s arguments given: (
 - There was no unreasonable delay as the issue has repeatedly been resolved only on an interim basis or for one proceeding only pending consideration in this proceeding, and CalCCA has consistently opposed a zero valuation; and (
 - The PD’s conclusory determination of prejudice to the IOUs ignores that the IOUs were on notice of CalCCA’s position and is unsupported by record evidence of reliance. (

¹ Acronyms used herein are defined in the body of this document.

The California Community Choice Association² (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure³ on the proposed **G&P#\$(D&%'2-\$A/- *?H/ C"(>%%&%(PD)** in this proceeding, dated August 13, 2026.

I. INTRODUCTION

Track 2 of this Power Charge Indifference Adjustment (PCIA) proceeding is the culmination of six years of litigation over a single issue: whether unbundled customers, who paid for renewable energy credits (RECs) banked before 2019 (Pre-2019 Banked RECs) when they were bundled customers but who later departed (Later Departed Customers), are entitled under the Public Utilities Code⁴ to receive their share of benefits when the RECs are later used by the investor-owned utilities (IOUs) to satisfy Renewables Portfolio Standard (RPS) compliance obligations for current bundled customers. The PD's answer – no – rests on multiple legal errors and must be rejected.

! "%&#the PD violates section 366.2(g) by treating indifference as a one-time determination rather than an ongoing statutory obligation to account for benefits that remain with bundled customers. Section 366.2(g) expressly requires that costs imposed on unbundled, community choice aggregator (CCA) customers **"%*"** be reduced by the value of any benefits **): *)(-&6 *-\$**(with bundled service customers.”⁵ Yet the PD states that “once the Commission adopts an indifference framework, we assume the framework will achieve indifference,” and therefore the indifference achieved in Decision (D.) 11-12-018 “is all the indifference mandates required.”⁶ This result constitutes legal error in that it fails to comply with the Commission's ongoing statutory obligation to account for benefits **): *)(-&6 *-\$**(with bundled customers.

Pre-2019 Banked RECs present a unique timing issue because their costs and benefits can be realized by different customers at different times. When the RECs were generated, then-departed

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, 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, Valley Clean Energy, and WestLight Energy.

³ **!"#\$%&'(#)*'+, *#%- ./)*0%1 ")*"\$2% (&3 3*22*&, 4%5.)\$2%&'%- +#0"\$0\$%# , 6%- +&0\$6. +\$4% (#)*'+, *#% (&6\$%&'% 5\$7.)#"\$&, 2 8*)\$%9:4% ; *<*2*&, %=4% (>#?"\$+%= (May 2021), as amended by 5\$2&)."*&, %@ABCDEF%GJune 11, 2026).**

⁴ All Section references herein are to the California Public Utilities Code unless otherwise noted.

⁵ Section 366.2(g) (emphasis added).

⁶ PD, at 32.

customers were credited through the PCIA for the value of the RECs they paid to generate, and then-bundled customers paid for those RECs in their generation rates.⁷ Indifference for then-departed customers was achieved—costs were allocated, and RECs changed hands. Some of those then-bundled customers, however, subsequently departed for CCA service and became Later Departed Customers. Although Later Departed Customers paid for the Pre-2019 Banked RECs while bundled, they never received benefits from their share of the banked RECs.

Those benefits arise when the share of the banked RECs that Later Departed Customers paid for through generation rates are used by the IOUs to satisfy current bundled customers' RPS obligations. The historical MPB credits to then-departed customers and subsequent compliance benefits for which the value must be provided to the customers that paid for them—i.e., current bundled customers and Later Departed Customers (which together were historically then-bundled customers)—are distinct benefits received by different customers at different times. Nothing in section 366.2(g) permits the Commission to disregard a benefit simply because it had not yet been realized—or could not yet be valued—when the associated costs were originally allocated. Nor does recognizing that benefit today retroactively modify D.11-12-018 or D.19-10-001. It prospectively applies section 366.2(g) to a benefit that ~~that \$"C(-86 *-\$%~~ with current bundled customers. Unless the PCIA recognizes that value, Later Departed Customers will have paid for RECs whose present compliance value they never receive, while current bundled customers retain the entire compliance benefit, ~~"(-6-881~~ In other words, the PD would have Later Departed Customers paying for others to benefit from the costs they paid, while they receive nothing.

~~() *+, - &~~the PD fails to make the findings required by section 1705 to support its conclusion that its resolution comports with section 366.2(g). The PD concludes that D.11-12-018 satisfied the “indifference mandates” when the renewable energy was generated and treats that historical determination as permanently resolving indifference with respect to those RECs. Without making all required findings, the PD’s conclusion lacks the factual and legal foundations required by law.

. / #, the PD concludes that CalCCA’s argument is untimely, and CalCCA should have previously sought rehearing on this question. This conclusion treats the Commission’s silence in D.11-12-018 and D.19-10-001 as an affirmative determination CalCCA was required to challenge on rehearing. Section 1731(b)(1), however, permits rehearing only “in respect to matters determined” in a

⁷ Exhibit (Ex.) CCA-1 at 9:8-17.

Commission action or proceeding. Neither decision determined the issue presented in Track 2. CalCCA cannot be faulted for failing to seek rehearing of a determination the Commission never made.

! +0#%&the PD's laches conclusion cannot be reconciled with the Commission's own treatment of this issue as unresolved. The Commission repeatedly and affirmatively – ~~IIJ0-6 &6~~ treated Pre-2019 Banked REC valuation as an open question and ultimately dedicated Track 2 for the express purpose of resolving it. CalCCA litigated that issue through the very process the Commission created. The Commission cannot now characterize CalCCA's argument as unfairly delayed because the Commission itself repeatedly treated the issue as unresolved.

Ultimately, the PD fails to provide Later Departing Customers the value of benefits for which they have paid. In fact, the PD's first Finding of Fact (FOF) reveals a bias the PCIA statutory framework precludes. This Finding describes the Legislature as "delegat[ing] to the Commission the task of creating a cost recovery and allocation framework)" (8\$%- &4#;\$; ' & (?#%) "6 & (-\$; †, & 8\$? & 111)"⁸ Nowhere in any of the FOFs, Conclusions of Law (COL), or Ordering Paragraphs (OP) does the PD recognize that the Legislature, through sections 366.2, 366.3, and 365.2, *'% (delegated to the Commission the task of preventing cost shifts between bundled and unbundled customers. Whether the omission of unbundled customers in FOF 1 is inadvertent or not, it captures the fundamental error that permeates the PD: indifference is not a one-way ratchet protecting bundled customers from cost shifts while permitting cost shifts to CCA customers. The Commission must fulfill the 8\$)+ &6 statutory mandate and protect 4"): (groups of customers from cost shifts.

Given the legal errors, the PD should be rejected and replaced with an Alternate PD that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A.

II. SECTION 366.2(G) REQUIRES THE COMMISSION TO CREDIT TO LATER DEPARTED CUSTOMERS THE CURRENT BENEFITS OF PRE-2019 BANKED RECS RETAINED BY BUNDLED CUSTOMERS

The costs and benefits associated with Pre-2019 Banked RECs must be equitably allocated to prevent cost shifts as required by section 366.2(g). As set forth below, the PD: (1) fails to recognize section 366.2(g)'s ongoing requirement to ensure indifference between unbundled and bundled customers; (2) errs by characterizing the later compliance benefit as duplicative when the historical MPB credit and later compliance benefit account for different benefits to different customers, at different times; (3) fails to account for the benefits remaining with bundled customers by concluding

⁸ PD, FOF 1 at 48 (emphasis added).

that D.11-12-018 permanently satisfied the indifference mandates for all future scenarios; (4) characterizes CalCCA's arguments as a request to modify D.11-12-018 and D.19-10-001, rather than the application of section 366.2(g) prospectively to a benefit being realized in the present; and (5) fails to recognize that a Pre-2019 Banked REC used to satisfy current bundled RPS compliance provides a benefit whose value must be accounted for under section 366.2(g).

A. Section 366.2(g) Requires the Commission to Ensure Ongoing Indifference

The PD violates section 366.2(g) by treating indifference as a one-time determination rather than an ongoing statutory obligation to account for benefits ~~to bundled customers~~. Typically, the allocation of PCIA costs and benefits between bundled and unbundled customers occurs within one ratemaking year.⁹ That is, a resource generates in year X, producing energy/Resource Adequacy (RA)/RPS value in year X, and customers pay the year X cost; the ERRRA Forecast/PCIA process allocates these year X costs and year X market values between bundled and unbundled customers.¹⁰ Banking a REC, however, preserves the REC's compliance benefit for use in a later compliance year. The Commission has repeatedly recognized this temporal distinction. For example, D.19-10-001's treatment of post-2018 banked RECs assigns no PCIA market value to an unused banked REC when it is generated, but recognizes its market value when it is subsequently used for bundled RPS compliance. Thus, even though Pre-2019 Banked RECs are subject to a different valuation methodology, the Commission has recognized that the generation and later compliance use of a banked REC are temporally distinct valuation events.

As noted in the PD's FOF 1, "[t]he Legislature . . . did not specify [in the indifference statutes] how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates."¹¹ Section 366.2(g) has no temporal requirement that costs and benefits have to occur simultaneously, and does not limit the benefits that must be recognized to those realized in the same year the underlying costs were incurred.¹² Instead, it broadly requires CCA customers' costs to be

⁹ Note that the determination in one ERRRA forecast year is subject to true-up in the following ERRRA forecast case.

¹⁰ !\$\$%6H%

¹¹ PD, FOF 1, at 48.

¹² That omission is significant because other provisions of section 366.2 expressly prescribe the relevant timeframe when the Legislature intended to do so. For example, section 366.2(f)(2) requires CCA customers to reimburse the IOU for electricity contract costs attributable to the customer "for the period commencing with the customer's purchases of electricity from the [CCA], through the expiration of all then existing electricity purchase contracts entered into by the [IOU]." !\$\$%Section 366.2(f)(2).

reduced by the value of “any benefits ~~); *)(-86 *\$(C):~~ bundled service customers.”¹³ The Commission therefore cannot disregard a benefit merely because it is realized after the associated costs were incurred.

Despite this, the PD concludes that D.11-12-018 satisfied the indifference requirements for Pre-2019 Banked RECs ~~4&"-80: &?"6 0'-*\$(48&+)%*(-%#&: &&(C&&(82&(-&'4& 1~~ This result contravenes section 366.2(g) and perpetuates the cost shift that the statute prohibits.

B.1 The PD Erroneously Characterizes Recognition of the Later-Realized Compliance Benefit as a Duplicative Payment

The PD wholly ignores the unique timing of Pre-2019 Banked RECs and the resulting impact on Later Departed Customers. Instead, it summarily concludes that “bundled customers . . . satisfied the indifference mandates, including section 366.2(g), when [they] credited departing load the market value of Pre-2019 Banked RECs in the years they were generated, in compliance with the indifference methodology adopted in D.11-12-018.”¹⁴ It therefore erroneously characterizes recognition of the later compliance benefit as requiring bundled customers to “credit the PCIA ~~*A*-\$~~ when these RECs are used for bundled compliance[,]” and concludes that requiring bundled customers to pay an “~~*, ; ,)+'\$*~~ cost to use the RECs now would violate the indifference statutes.”¹⁵

These characterizations are wrong. There is ~~\$(; #0'-?*)-2&0*96 &)~~ because the historical MPB credit and the later compliance benefit account for different benefits, to different customers, at different times. The historical MPB credit accounted for the market value of the RECs in the year they were generated and ensured that then-departed customers were paid the costs of those RECs under the methodology adopted in D.11-12-018. It did not compensate customers who were still bundled when the RECs were generated and banked — and therefore still paying their share of the costs—but who departed before those RECs were later used for bundled RPS compliance. Indeed, those Later Departed Customers could not have received the historical PCIA credit because ~~); 80(C&&%)+'(4#&; '& (?#%)'6 &% *)0: 80-6 &(~~

The distinction is critical. Compliance with D.11-12-018 in the generation year does not eliminate the separate requirement of section 366.2(g) to account for benefits that “remain with bundled service customers.” Under the PD, the entire later-realized compliance benefit remains with the IOUs, providing the IOUs with a windfall in that they get to keep the Later Departed Customers’ share of the RECs for their bundled customers , ~~"-(-&&~~ Section 366.2(g) does not permit that result. Providing Later

¹³ Section 366.2(g) (emphasis added).

¹⁴ PD, COL 1, at 51.

¹⁵ PD, at 3, 11 (emphasis added), and COL 3-4, at 51-52.

Departed Customers their share of the benefit does not credit them “again”; it credits them for a benefit they paid for but never received.

C.1 The Commission Cannot Presume D.11-12-018 or D.19-10-011 Satisfied Section 366.2(g) Without Determining Whether Benefits Remaining with Bundled Customers are Accounted For

The PD attempts to satisfy section 366.2(g)'s requirements by relying on the Commission's adoption of D.11-12-018 and D.19-10-001. The PD notes that "[t]he Legislature delegated to the Commission the task of creating a cost recovery and allocation framework to ensure bundled customer indifference. . . ." and that "[o]nce the commission adopts an indifference framework, C&P# 80: &,-*6 &C"-HC+('?: +2&(\$; †,&\$?&'¹⁶ The PD then concludes that "the indifference mandates required" was the payment in the years the renewable resources were generated because "[d]eparting load's PCIA rates contemporaneously decreased by the remaining benefits of those resources as determined by the commission – their market values – satisfying 366.2(g)."¹⁷ The PD's analysis stops there.

But adoption of that cost allocation methodology is not itself evidence that the Commission has accounted for all benefits section 366.2(g) requires it to allocate. The PD's conclusion that the Commission need not prospectively adjust its methodology to address a benefit realized years later that was never accounted for contravenes section 366.2(g). When that occurs, the Commission must modify that methodology to comply with the statute. Indeed, the Commission has done exactly that before, including in D.18-10-019, when it modified the PCIA methodology to create a true-up,¹⁸ and in the recent Track 1 Decision, when it modified the RA benchmark.¹⁹ Decision 11-12-018 did not achieve indifference for Pre-2019 Banked RECs because the decision did not contemplate or address the issue. The statutory requirement controls the methodology – not the other way around.

In addition, the PD’s reliance on D.19-10-001 and the Working Group Report leading up to it for the proposition that valuation of Pre-2019 Banked RECs was discussed and “undisput[ably] resolved” is legal error. The PD states that CalCCA acknowledged that Pre-2019 Banked RECs were already “fully

¹⁶ PD, at 32, and FOF 1, at 48 (emphasis added).

¹⁷ PD, at 32 (citing JIOU-02 at 17); 28 CFR § 8, at 49, and COL 1, at 51.

¹⁸ D.18-10-019, COL 1, at 156 (“The Commission’s current PCIA methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 . . . and should be revised as specified in this decision.”).

¹⁹ D.25-06-049, COL 1, at 33 (“The Commission’s current RA MPB calculation methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 and should be revised as described in this decision.”).

allocated” through the D.11-12-018 cost allocation methodology in the Report from the Working Group Report (co-led by CalCCA and PG&E) that states that Pre-2019 Banked RECs “have already been bought and paid for by bundled customer[s] at previous years’ RPS Adders.” In addition, the PD notes that Pre-2019 Banked RECs were exempted from the Commission’s post-2018 methodology adopted in D.19-10-001. Therefore, the PD surmises that “allocating an additional cost to bundled customers to use these RECs would violate indifference mandates.”²⁰ However, neither the Working Group Report nor D.19-10-001 actually addressed precluding the non-zero valuation of benefits accruing for Later Departed Customers when the IOUs later use Pre-2019 Banked RECs for their bundled customer RPS compliance. They were both silent on the issue and cannot be used now to support the PD’s claims that the indifference mandates had already been fully satisfied.

D.1 Accounting for the Compliance Value of Pre-2019 Banked RECs When that Benefit is Realized is a Prospective Application of Section 366.2(g)

The PD claims that what CalCCA is really arguing is “that the Commission erred in D.11-12-018 and that the pre-2019 PCIA methodology ~~was~~ **entitled** Later Departed Customers to some future value for the Pre-2019 Banked RECs under the indifference mandates. It did not.”²¹ This argument puts words in CalCCA’s mouth. CalCCA does not contend that D.11-12-018 was erroneous when issued. The decision simply did not contemplate Later Departed Customers, which makes sense. Future departed load was uncertain. Direct access was capped, and the one CCA that existed in 2011, Marin Clean Energy, had just narrowly survived PG&E’s statewide ballot proposition aiming to stop the CCA movement. Another CCA did not form until three years later. CalCCA did not even exist at that time. The PD itself recognizes “the Commission did not recognize Later Departing Load in D.11-12-018.”²²

The PD further states that “the alleged cost shift CalCCA seeks to rectify pursuant to section 366.2(g) ~~is not a cost shift~~.”²³ But there was no cost shift that occurred under the pre-2019 methodology vis-à-vis these RECs. The relevant benefit had not yet been realized. The compliance benefit arises ~~when an IOU uses a Pre-2019 Banked REC to satisfy its current bundled customers’ RPS compliance obligation~~; ~~CalCCA seeks recognition of the benefit when it is realized, as section 366.2(g) requires~~. The PD acknowledges both the “remaining benefits” of RPS resources and

20 PD, at 37.

²¹ PD, at 35 (emphasis added), and FOF 14, at 50.

22 PD, at 35.

²³ I/*6H (emphasis in original).

that “PCIA rates must be offset” by those benefits.²⁴ Yet it concludes that because D.11-12-018 did not establish a mechanism through which customers departing in later years would receive their share of those subsequently realized benefits, no such value may be recognized now.²⁵ That again reverses the statutory hierarchy. The absence of a historical methodology for allocating a benefit that would be realized in the future cannot override section 366.2(g)’s requirement to account for a benefit when it ~~is realized~~: bundled customers. As the PD itself recognizes, “[t]he Commission has the discretion to make modifications to the PCIA effective on a prospective basis.”²⁶

Nor does prospective recognition of the compliance benefits require the Commission to revisit the historical rates established under D.11-12-018. Those rates remain undisturbed. CalCCA does not seek to recalculate the market value assigned to Pre-2019 Banked RECs in their generation years, refund amounts collected under historical PCIA rates, or compensate customers for a historical cost shift. It seeks to account for a different benefit being realized ~~by~~ the use of Pre-2019 Banked RECs to satisfy current bundled customers’ RPS compliance obligations.²⁷ Applying section 366.2(g) to that current benefit is prospective, not retroactive.

E. The Commission Cannot Recognize that Pre-2019 Banked RECs Satisfy Current Bundled RPS Compliance While Assigning that Compliance Benefit Zero Value Under Section 366.2(g)

Finally, the Commission cannot reasonably recognize that Pre-2019 Banked RECs satisfy a current RPS compliance obligation while simultaneously treating the benefit of that compliance as having zero value for purposes of section 366.2(g). When an IOU removes a Pre-2019 REC from the bank and uses it for current bundled customer RPS compliance, that REC satisfies a compliance obligation that otherwise must be satisfied with other RPS procurement. The banked REC provides a present compliance value to bundled customers, even though the costs associated with acquiring that REC were originally paid pre-2019 by both current bundled customers and Later Departed Customers. The PD’s zero-value result therefore cannot be reconciled with the statute, and should be rejected.

²⁴ IG.

²⁵ PD, at 36, and FOF 5, at 49.

²⁶ PD, at 35; 2§§#)2&#Section 1708 (“The Commission may at any time . . . rescind, alter, or amend an order or decision made by it.”).

²⁷ Indeed, this answers the question raised by the PD in footnote 110 as to why CalCCA “does not contest the appropriateness of the use of prior market values to compensate departing load under the pre-2019 methodology...” A different benefit must now be realized.

III. THE COMMISSION FAILED TO MEET SECTION 1705 REQUIREMENTS TO MAKE FINDINGS AND CONCLUSIONS ON ALL ISSUES MATERIAL TO THE DECISION

The PD fails to make the findings required by section 1705 to support its conclusion that assigning the entire compliance value to current bundled customers while providing zero value to Later Departed Customers for Pre-2019 Banked RECs satisfies the statutory indifference requirements today. Section 1705 requires that Commission decisions “contain, separately stated findings of fact and conclusions of law . . . on *“(the § 6 *) & #’ 0’ 0: &’ -; & (’ - 6 & #’ \$ 10*”²⁸ The California Supreme Court has stated that “[e]very issue that must be resolved to reach [an] ultimate finding is ‘material to the order or decision.’”²⁹ The Commission therefore must make the requisite findings upon which that ultimate conclusion rests.³⁰ Such findings “afford a rational basis for judicial review,” allowing a reviewing court to do more than “only guess at how” a conclusion was reached.³¹ An ultimate conclusion supported only by “bare-bones conclusory findings” is insufficient because the findings must disclose the factual and analytical basis for the Commission’s determinations.³²

The PD fails to make adequate findings directly addressing the indifference requirements. The Commission does not find that the ongoing indifference requirements of section 366.2(g) have been satisfied for Later Departed Customers and that those customers have received value for the benefits remaining with bundled customers. Neither does the Commission find that Later Departed Customers did not “experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.”³³ The only related FOF that speaks directly to the cost shift – rather than the alleged delay in bringing the claim – is as follows:

FOF 4. . . . The Commission did not recognize “Later Departing Load” as a customer group in D.11-12-018 in any way.

FOF 9. The alleged cost shift CalCCA is attempting to rectify pursuant to . . . section 366.2(g) existed under the pre-2019 framework.

The PD therefore states that the cost shift only occurred pre-2019, and it was implicitly addressed in 2011 and again in 2019, despite failing to recognize Later Departed Load as a customer group.

The PD’s COL likewise are insufficient and, again, fail to address Later Departed Customers.

²⁸ Section 1705 (emphasis added).

²⁹ *(#)*’&+, *## J &’&+8+#, 2?H% (&H%<H% - . /H% 1 “*)2H% (&3 3K, (1963) 59 Cal.2d 270, 273.*

³⁰ *I6H (citations omitted).%*

³¹ *I6H at 274 (citations omitted).*

³² *8&L#&+6% 1 “*)”M%5#”\$%N&+ 3 #)*0#”*&, %<H% - . /)*0% 1 “*)2H% (&3 3K, (1978) 22 Cal.3d 529, 540; (#)*’&+, *## J &’&+4% 59 Cal.2d at 273; P+\$M>&. , 6%A*, \$24%I, 0H%<H% - . /H% 1 “*)2H% (&3 3K, (1967) 65 Cal.2d 811, 813.*

³³ Sections 366.3, 365.2.

COL 1. Bundled customers of SDG&E, SCE, and PG&E satisfied the indifference mandates, including section 366.2(g), when bundled customers credited departing load the market value of Pre-2019 Banked RECs in the years they were generated, in compliance with the indifference methodology adopted in D.11-12-018.

COL 4. Because the indifference mandates were satisfied under the pre-2019 methodology, to require current bundled customers to pay an additional cost to use the resources for which costs have already been allocated under the pre-2019 methodology would violate the indifference mandates.

The PD's characterizations result in a sidestepping of the inquiry necessary to answer the "issues material to the . . . decision": whether unbundled customers, who paid for Pre-2019 Banked RECs when they were bundled but who later departed, are statutorily entitled to receive their share of benefits when the RECs are later used to satisfy the RPS compliance obligations of current bundled customers. The PD therefore fails to satisfy the requirements of section 1705 and should be rejected.

IV. THE PD'S UNTIMELINESS FINDING IS INCONSISTENT WITH SECTION 1731(B)(1) BECAUSE CALCCA COULD NOT HAVE CHALLENGED A MATTER THE COMMISSION NEVER DETERMINED

The PD recasts CalCCA's position from seeking indifference)"; *9 under section 366.2(g) into an attempt to reverse the alleged indifference treatment of Pre-2019 Banked RECs in D.11-12-018 and D.19-10-001.³⁴ In doing so, the PD concludes not only that those decisions already satisfied the indifference mandates, but also that CalCCA's position is untimely because CalCCA failed to seek rehearing of those decisions pursuant to section 1731(b)(1).³⁵ The PD's conclusion fails because neither D.11-12-018 nor D.19-10-001 *?)#*"9; 3&6 \$8 the indifference treatment applicable when Pre-2019 Banked RECs are later used for bundled customer RPS compliance. The Commission was silent on that issue, and CalCCA and its CCA members could not have sought rehearing of determinations the Commission never made.

The PD attempts to transform that silence into an affirmative determination. It states that, "at the time [the Commission] adopted the decision that required bundled customers to pay for RECs in the year they were generated and that omitted credits for customers who were not yet departing load,"(the Commission knew those RECs could be banked and was aware of the statutory requirement to prevent cost shifts.³⁶ The PD then reasons that "[y]et the Commission's 2011 decision did not adopt a framework that required the RECs to be valued again in the year the RECs are used to satisfy bundled

³⁴ !\$\$PD, at 38, and FOF 14, at 50.

³⁵ !\$\$PD, at 37-39, FOF 15-16, at 50, COL 6, at 52.

³⁶ PD, at 41-42.

Working Group Report addressed how to maintain indifference for Later Departed Customers when those Pre-2019 Banked RECs are subsequently used.⁴²

CalCCA and its members had no determination on this issue that they could challenge on rehearing. Its Track 2 position cannot be deemed untimely for failing to challenge a determination that did not exist. The PD also cannot supply that determination now and retroactively fault CalCCA for failing to challenge it years earlier. The PD's untimeliness conclusion, and the PD, should be rejected.

V. THE COMMISSION'S REPEATED TREATMENT OF PRE-2019 BANKED REC VALUATION AS AN UNRESOLVED ISSUE CONFIRMS THAT CALCCA'S CLAIM IS NOT BARRED BY LACHES

CalCCA and its member CCAs have diligently and consistently pursued the argument that all customers who paid to generate Pre-2019 Banked RECs used for bundled customer compliance must receive their share of the benefits of those RECs. The record in this proceeding and the multiple prior proceedings in which this issue was disputed demonstrate that these arguments are timely, ripe, and appropriate for decision on the policy merits in this proceeding.

Nevertheless, the PD erroneously adopts the Joint IOUs' argument that laches bars CalCCA from raising its claims in this proceeding because CalCCA and its members failed to file for rehearing of D.11-12-018 or D.19-10-001.⁴³ Laches is an equitable doctrine that prevents a party who has 'slept on their rights' from raising them too late in a way that is unfair to another party.⁴⁴ Laches, therefore, requires both "unreasonable delay" and a resulting "prejudice" (or acquiescence).⁴⁵ The reasonableness of an alleged delay is a fact-based question that turns on what a party "knew or with reasonable inquiry should have known."⁴⁶ Neither unreasonable delay nor prejudice occurred here, resulting in legal error through the PD's finding that laches bars CalCCA's arguments.

A. Unreasonable Delay Does Not Exist Because Neither D.11-12-018 Nor D.19-10-001 Resolved the Question of Pre-2019 Banked REC Value, and Only Recently Did the IOUs Start Predicting the Need to Use Pre-2019 Banked RECs

As a threshold matter, CalCCA's claim regarding Pre-2019 Banked RECs cannot be characterized as unreasonably delayed. CalCCA has challenged the Joint IOUs' proposals to value Pre-

⁴² In fact, SCE filed an Application for Rehearing on the exact question of whether D.19-10-001 conclusively determined the value of Pre-2019 Banked RECs when used for RPS compliance, and the Commission punted, leaving the ambiguity to be resolved in a later rulemaking. D.24-08-004, at COL 3-4.

⁴³ PD, at 40.

⁴⁴ D.15-05-004, at 22.

⁴⁵ 24 Cal.4th 61, at 68; 22 D.15-02-040, at 7.

⁴⁶ D.95-02-016, at COL 4-5.

2019 Banked RECs at zero in all Commission proceedings in which the question has been at issue, and the issue has never been resolved. For laches to apply, CalCCA must have been on notice that the Commission believed the issue had already been decided. The actions of CalCCA, other parties, and the Commission itself demonstrate it was reasonable to consider this issue unresolved, and that this rulemaking forum is the appropriate forum in which to address this question. None of the Commission's twelve prior decisions addressing this issue suggested that the issue had already been decided.

The Commission's statements in ERRA cases demonstrate the reasonableness of CalCCA's position that this question had not been previously addressed. The Commission regularly declines to decide issues that are not ripe,⁴⁷ and declines to decide open policy questions in the ERRA cases.⁴⁸ That occurred as recently as December for these RECs, when the Commission continued its pattern of deciding the Pre-2019 Banked REC question on "interim" or "for this case only" grounds.⁴⁹ In PG&E's 2026 ERRA Forecast Decision, for example, the Commission found "that PG&E's proposal [to value Pre-2019 Banked RECs at zero] is reasonable ~~"\$(*\$(\$)& 6 (4*%\$)"~~ while awaiting a more comprehensive decision on use of banked RECs in a rulemaking."⁵⁰ That Decision explicitly found that D.19-10-001 "did not conclusively resolve how to value pre-2019 RECs," and adopted PG&E's proposal "on an interim basis for the purpose of this decision" because the question was complicated, the subject of "conflicting understandings" and "appropriate for consideration in a rulemaking."⁵¹

The PD also acknowledges but erroneously disregards that the Commission has already granted the identical relief CalCCA is asking for (i.e., valuation of Pre-2019 Banked RECs at the RPS MPB) three times (PG&E's 2023, 2024, and 2025 ERRA Forecast decisions).⁵² This conclusion is inconsistent with any finding that CalCCA's claim is stale, abandoned, untimely, or unreasonably delayed. How could the Commission have found that CalCCA's proposal resulted in just and reasonable rates in these

⁴⁷ D.18-11-005, at 4 (citing D.18-05-050, at 3).

⁴⁸ OIR, at 10 ("the [2026 Energy Resource Recovery Account (ERRA)] process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy.")

⁴⁹ D.25-12-028, at 111-113, COL 14 (treating resolution as "interim"); D.25-12-027, at FOF 15 ("on an interim basis for the purpose of this decision"); D.24-12-039, at 68 (approving treatment "for this proceeding"); D.24-08-004, at 5 (denying SCE's Petition for Modification and saying the Commission "may consider the issue in a future rulemaking"); D.23-11-094, at 60 (treating resolution as "interim").

⁵⁰ D.25-12-027, at 26.

⁵¹ D.25-12-027, at 31.

⁵² PD at 42.

three decisions and then now decide that the matter had already been clearly resolved to ~~0-828~~(such treatment over a decade ago?

Additionally, the Joint IOUs only recently started considering the need to use Pre-2019 Banked RECs. And while the PD notes that “actual harm is not a condition precedent to challenging a Commission decision,”⁵³ it is clear that parties and the Commission were working together to delay the consideration of the issue to this rulemaking. The Commission even ordered the IOUs to exhaust Post-2018 Banked RECs before turning to Pre-2019 Banked RECs.⁵⁴ In every proceeding in which this issue was explicitly raised, CalCCA opposed valuing Pre-2019 banked RECs at a zero-dollar valuation. Now the issue has finally come to a head. Indeed, the Scoping Memo launching this Track 2 characterized the Pre-2019 Banked REC valuation question as one that had “emerged as exigent.”⁵⁵ Characterizing CalCCA’s position as unreasonably delayed therefore ignores the facts and should be rejected.

B.1 The PD’s Determination of Prejudice Ignores that the Joint IOUs Were on Notice of CalCCA’s Arguments and is Unsupported by Record Evidence of Reliance

The PD also erroneously adopts the Joint IOUs’ laches argument by finding prejudice to the IOUs by CalCCA failing to earlier raise its claims. This finding, however, ignores the history of this dispute and prior positions, and relies on unsupported factual claims. First, the Joint IOUs have been aware that CalCCA and its members have considered this a disputed issue for years and have consistently raised their arguments in applications and rulemakings. The PD claims that CalCCA’s alleged delay “prejudiced other stakeholders” because those stakeholders lost their opportunity to “advocate for the redress of other past cost shifts” and because they “made procurement, allocation, and market offer decisions.”⁵⁶ But the IOUs made their decisions while on notice that CalCCA considered this matter disputed for all the reasons described ~~90-*~~. The IOUs – like the CCAs – made procurement, allocation, and market offer decisions under conditions of uncertainty as this issue remained unresolved.

In fact, the Joint IOUs themselves claimed that the valuation of banked RECs was a live issue as recently as 2023. In R.17-06-026 (and after D.19-10-001) the parties responded to an ALJ request for them to identify what issues remained to be addressed. In SCE’s Comments in response, it included:

How the IOUs should account for the use of banked Renewable Energy Credits (RECs) for RPS compliance. Stakeholders have observed that there is no guidance on how the IOU should account

⁵³ PD at 41.

⁵⁴ !\$\$4%\$H7H, D.23-11-094, COL 5-7, OP 9.

⁵⁵ R.25-02-005, @3\$, 6\$6%!0&?*, 7% J \$3& (Feb. 3, 2026), at 2.

⁵⁶ PD, at 41.

for its use of banked RECs for RPS compliance purposes. The underlying issue is to ensure that the value of the those banked RECs is appropriately accounted for in the IOUs' PABA, adopted in this proceeding in 2018, when and if they are used for the IOU's RPS compliance.⁵⁷

At the time, CalCCA agreed, noting that the Commission should address questions related to “the value that will be placed on the RECs, and specific methodologies for tracking excess RECs and whether they have been previously charged to customers.”⁵⁸ PG&E's Reply Comments also agreed with SCE, stating that SCE's Comments “correctly recognize that there is no guidance on banked REC accounting.”⁵⁹ The Joint IOUs' claim of laches is therefore itself untimely, and they cannot demonstrate that they were prejudiced by any alleged delay. Laches is an equitable remedy, and a finding of laches is improper when the invoking party's hands are themselves not clean.⁶⁰

Lastly, the application of laches in this instance runs counter to the practice CalCCA reasonably believed the Commission employs in rulemakings: permitting parties to raise legal and policy arguments as to how the Commission can accomplish its statutory and constitutional obligations prospectively. CalCCA was unable to find any historical instance in which the Commission used laches to reject a party's argument made through testimony and briefing in a rulemaking. The PD's reliance on laches to reject to CalCCA's claims must be rejected as legally erroneous.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein. For all the foregoing reasons, the PD should be rejected and replaced with an Alternate PD that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A.

⁵⁷ Q?\$, *, 7% (& 3 3\$, "2%&'! (R%&, %@ABK2%5.)*, 7%5\$\$. \$2"* , 7% (& 3 3\$, "2%&, %! . ??)\$3\$, "#)%P+\$\$, >&. 2\$%P#2CT+\$%\$ - +&?&2#)%#, 6%I22. \$2%*, %!0&?\$, R.17-06-026 (Nov. 7, 2022), at 4.

⁵⁸ (#) ((@K2% (& 3 3\$, "2%&, %@ABK2%5.)*, 7%5\$\$. \$2"* , 7% (& 3 3\$, "2%&, %! . ??)\$3\$, "#)%P+\$\$, >&. 2\$%P#2CT+\$%\$ - +&?&2#)%#, 6%I22. \$2%*, %!0&?\$, R.17-06-026 (Nov. 7, 2022), at 15.

⁵⁹ 5\$?)M% (& 3 3\$, "2%&' - PUR"%&@63*, *2"+#"%<\$A#L%B.67\$K2%5.)*, 7%5\$\$. \$2"* , 7% (& 3 3\$, "2%Q, %PVPCT+\$%\$ 5\$2&. +0\$2%!. ??)\$3\$, "#)%R, \$+7M%; *<*2%&, %!"#"" - +&?&2#)%#, 6%I22. \$2%*, %!0&?\$, R.17-06-026 (Nov. 7, 2022), at 5.

⁶⁰ D.15-02-040, at 7 (“Laches is an equitable doctrine, and the party invoking laches must “come with clean hands.” (13 Witkin, Summary of Cal. Law (10th ed. 2005) Equity, § 9; 2\$%\$ - +\$0*2%&, %I, 2"+. 3\$, "% J '7H% (&H%<H% @. " & 3&"<\$% J #*, "\$, #, 0\$% J #0>*, \$+M% (&H (1945) 324 U.S. 806, 814 (unclean hands “closes the doors of a court of equity to the one tainted with inequitableness or bad faith relative to the matter in which he seeks relief”).

Respectfully submitted,

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Leanne Bober,
Director of Regulatory Affairs and Deputy
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CALIFORNIA COMMUNITY CHOICE
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September 2, 2026

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

**APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED DECISION RESOLVING TRACK TWO ISSUES**

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

All Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Proposed Decision shall be rejected and replaced with the following:

FINDINGS OF FACT

1. The Legislature delegated to the Commission the task of creating a cost recovery and allocation framework to prevent cost shifts between bundled and unbundled customers and did not specify how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates.
2. RECs generated by the investor-owned utilities prior to 2019 and subsequently banked present a unique timing issue because their costs and benefits can be realized by different customers at different times.
3. In D.11-12-018, the Commission revised the PCIA market price benchmark to incorporate an adder to reflect the market value of RPS-compliant renewable resources in the PCIA.
4. Before 2019, when RECs were generated by PCIA resources, customers that had already departed bundled service were credited through the PCIA for the value of the RECs they paid to generate.
5. Before 2019, then-bundled customers paid for all of the RECs generated by the IOUs' PCIA resources in their generation rates, as required by D.11-12-018. If the investor-owned utility did not need the RECs at that time to satisfy the RPS compliance needs of their bundled customers, the investor-owned utility could bank the RECs for later use.
6. After paying for the RECs in generation rates, some then-bundled customers subsequently departed for CCA service and became Later Departed Customers.
7. IOU bundled customers receive benefits from Pre-2019 Banked RECs when the IOUs use those RECs to satisfy a portion of these bundled customers' RPS compliance obligations.
8. These benefits arise from both the share of Pre-2019 banked RECs that current bundled customers paid for through generation rates and from the share of the Pre-2019 banked RECs that Later

Departed Customers paid for through their own generation rates when they were bundled customers.

9. Although Later Departed Customers paid for the Pre-2019 Banked RECs while bundled, they never received benefits from their share of the banked RECs.

10. The historical MPB credit to then-departed customers and the subsequent compliance benefit retained by current bundled customers are not duplicative; they are distinct benefits received by different customers at different times.

11. Recognizing the benefits to current bundled customers when the IOUs remove Pre-2019 Banked RECs from the bank and use them for RPS compliance, and providing to Later Departed Customers the value of the share of those benefits for which they paid, satisfies the requirement of Section 366.2(g) that benefits that remain with current bundled customers be credited or allocated to Later Departed Customers.

12. Unless the PCIA recognizes that value, Later Departed Customers will have paid for RECs whose present compliance value they never receive, while current bundled customers retain the entire compliance benefit for free, resulting in a cost shift to Later Departed Customers.

13. Crediting the value of—or allocating—Pre-2019 banked RECs to the customer vintage of the year in which a REC was banked provides benefits to all customers who paid for those RECs in proportion to their load (including current bundled customers), and does not provide any new PCIA credit to customers who departed before those RECs were banked.

CONCLUSIONS OF LAW

1. Section 366.2(a)(4) requires that the implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.

2. Section 366.2(f) requires customers purchasing electricity from a community choice aggregator to reimburse the electrical corporation that previously served the customers for net unavoidable electricity costs attributable to that customer.

3. Section 366.2(g) requires that estimated net unavoidable costs paid by the customers of the community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.

4. The Commission has a statutory obligation to ensure ongoing indifference between bundled and unbundled customers.

5. D.11-12-018 adopted a PCIA methodology governing the allocation of costs and benefits of RECs between then-bundled customers and already departed customers at the time of generation of the REC.
6. To prevent a cost shift to Later Departed Customers in violation of Sections 366.2(a)(4) and (g), the Commission must ensure customers that departed bundled service after a REC was generated prior to 2019 receive value, when that REC is removed from the bank by the investor-owned utility to be used for RPS compliance on behalf of its current bundled customers.
7. Requiring current bundled customers to compensate Later Departed Customers for the use of Pre-2019 Banked RECs that were originally paid for by Later Departed Customers does not constitute an unlawful shifting of costs to current bundled customers.
7. The Commission should value Pre-2019 Banked RECs at the current Renewables Portfolio Standard Market Price Benchmark for the purpose of calculating Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's annual Power Charge Indifference Adjustment indifference amounts.

ORDERING PARAGRAPHS

1. Renewable Energy Credits generated prior to January 1, 2019, and banked shall be valued at the current Renewables Portfolio Standard Market Price Benchmark for the purpose of calculating Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's annual Power Charge Indifference Adjustment indifference amounts.

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2. The methodology adopted in this decision shall be effective immediately and shall be incorporated into each investor-owned utility's 2027 Energy Resource Recovery Account October updates, impacting 2026 true-ups and 2027 forecasted rates.
 3. Rulemaking 25-02-005 remains open.
- This order is effective today.