NOVEMBER FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commissions Approved Energy Resource Recovery Account (ERRA) Trigger Mechanism (U 39 E)	Application No. 25-09-015 (Filed September 30, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

PUBLIC VERSION

Leanne Bober
Director of Regulatory Affairs and
Deputy General Counsel
Willie Calvin
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Nikhil Vijaykar
Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com
tlindl@keyesfox.com

November 3, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

SUMMARY OF RECOMMENDATIONS

The Commission[1] should adopt the recommendations in CalCCA's Opening Brief, with the exception of the recommendations related to CalCCA's AFR of D.25-06-049, which are now moot.

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commissions Approved Energy Resource Recovery Account (ERRA) Trigger Mechanism (U 39 E)	Application No. 25-09-015 (Filed September 30, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the procedural schedule established by the Assigned Commissioner's Scoping Memo and Ruling[2] (Scoping Memo) as modified by the Administrative Law Judge's E-mail Ruling Small Business Utility Advocates Procedural Request for Extension of Briefing Schedule (Pacific Gas & Electric 2026 Energy Resource Recovery Account) issued October 17, 2025[3] (affirmed by the ALJ's October 30 Email Ruling Clarifying Procedural Schedule[4]), California Community Choice Association[5] (CalCCA) hereby submits this Reply

---

[2] *Assigned Commissioner's Scoping Memo and Ruling*, A.25-05-011 (Jul. 31, 2025), at 4.

[3] *E-mail Ruling Small Business Utility Advocates Procedural Request for Extension of Briefing Schedule*, A.25-05-011 (Oct. 17, 2025).

[4] *Email Ruling Clarifying Procedural Schedule*, A.25-05-011 (Oct. 30, 2025).

[5] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast

Brief in the *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 (U39E)* (Application).

CalCCA's Opening Brief demonstrates: (1) Pacific Gas and Electric Company's (PG&E) banked Renewable Energy Credit (REC) proposal violates Section 366.2(g) of the Public Utilities Code[6] and does not comply with the settled indifference framework because departed customers who paid for RECs generated prior to 2019 do not receive the value of those RECs when they are used for bundled customer compliance; and (2) PG&E's Resource Adequacy (RA) Slice-of-Day (SoD) valuation proposal is unjust and unreasonable. PG&E's Opening Brief fails to repair these shortcomings.

On banked RECs, PG&E argues for <u>bundled customer</u> affordability, but willfully ignores that its proposal would achieve affordability by unlawfully shifting costs onto <u>departed customers</u>. In fact, PG&E's Opening Brief makes clear that pushing the costs of PG&E's Renewables Portfolio Standard (RPS) compliance onto departed customers is central to the utility's procurement strategy. The Commission, however, must not permit PG&E to violate a fundamental requirement of the indifference framework to execute its utility-friendly RPS strategy. PG&E also insists pre-2019 banked RECs were "fully valued" in the past, and should not be trued-up now,

---

Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[6] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

but ignores a crucial set of customers who have never received value for pre-2019 banked RECs: the customers who were bundled at the time the banked RECs were generated, but have since departed PG&E's bundled service. Crediting these "then-bundled, now-departed" customers for PG&E's use of pre-2019 banked RECs cannot and does not constitute a true-up because those customers never received value for those RECs in the first place—there is nothing to true-up. PG&E also strenuously argues its banked REC proposal would avoid increasing bundled customer costs as a result of load departures, but in fact, no such risk exists. By crediting departed load for PG&E's use of banked RECs as CalCCA recommends, PG&E would fairly compensate the customers who previously paid for those RECs, without double-charging any bundled customers. PG&E similarly misses the mark where it claims a credit to departed load would constitute an unlawful "refund." PG&E's own practices undermine this argument—the utility has routinely credited Power Charge Indifference Adjustment (PCIA) vintages for its use of banked RECs, including vintages prior to 2019. PG&E's various arguments in support of its unlawful proposal, therefore, each fail.

Similarly, in support of its RA SoD valuation proposal, PG&E claims that proposal would ensure its Retained RA quantity for battery resources is consistent with its forecasted retained use of those resources. But PG&E's revised RA SoD methodology is heavily predicated on its optimized dispatch of its battery resources, and in particular, on the optimized dispatch in the California Independent System Operator (CAISO) peak hour. That not only means PG&E's methodology would produce a different discount for battery value (relative to baseload value) if applied by a different load-serving entity (LSE),[7] it also means PG&E's methodology could produce a different volume of battery storage RA in the CAISO peak hour (and accordingly, a different discount for battery value) <u>every time PG&E re-runs its dispatch optimization.</u> That result makes no sense in the context of the PCIA framework, where the objective is to determine the <u>market</u> value of the RA attributes of storage resources—that value should not vary based on the manner a single market participant (PG&E) optimizes the batteries. PG&E also claims its RA SoD methodology reflects observed market value and the value PG&E assigns battery RA when it seeks to procure resources for its bundled customers. But the record evidence contradicts PG&E's argument; in fact, PG&E's RA SoD proposal significantly undervalues the RA value of batteries relative to PG&E's internal valuation. While the Commission should permit parties to analyze this issue holistically in the PCIA Rulemaking before reaching any conclusions regarding the impacts of SoD on the PCIA framework, to the extent the Commission is inclined to adopt an interim modification to PG&E's RA valuation practices in this proceeding, it should direct PG&E to adopt Southern California Edison Company's (SCE) interim SoD method. Contrary to PG&E's claims, the record includes sufficient information for PG&E to implement SCE's method.

I. STATE LAW AND COMMISSION PRECEDENT REQUIRE PG&E TO VALUE PRE-2019 BANKED RECS

A. PG&E'S OPENING BRIEF LAYS BARE THE UTILITY'S RPS STRATEGY OF SQUEEZING DEPARTED CUSTOMERS TO REDUCE COSTS FOR THE BENEFIT OF BUNDLED CUSTOMERS

In past years, PG&E and CalCCA have largely seen eye-to-eye with respect to the valuation of banked RECs. PG&E has consistently valued banked RECs (including pre-2019 banked RECs)

---

[7] *See* Evidentiary Hearing Tr. Vol. 1, at 70-71 (witness Keller acknowledging that PG&E's methodology, if applied by a different investor-owned utility (IOU), could produce a different discount for battery value relative to baseload resources).

at the applicable RPS Adder in the year those RECs are retired and credited the PCIA vintage corresponding to the year those RECs were generated. CalCCA has supported that methodology because it is lawful, fair and equitable. In short, PG&E's past practice mirrors the methodology CalCCA continues to support in this case. And the Commission has approved that methodology—in 2022, 2023, and 2024.[8]

In this case, PG&E proposes to use pre-2019 banked RECs without crediting the departed customers who paid for those RECs when they were generated. The record leaves no doubt that PG&E's proposal is a sharp departure from its practice in past ERRA Forecast cases.[9] PG&E's Opening Brief does not acknowledge that departure; however, it nevertheless lays bare the reason why PG&E so strikingly changes its tune in this case.

In December 2024, the Commission issued Decision (D.) 24-12-035, approving PG&E's 2024 RPS Plan. Under that Plan, PG&E intends to lean on banked RECs for RPS compliance for the foreseeable future.[10] According to PG&E, that strategy "promote[s] bundled service customer affordability."[11] But, according to PG&E, that strategy can only promote "bundled service customer affordability" if the Commission allows PG&E to assign pre-2019 banked RECs zero value (*i.e.*, allow bundled customers to use those RECs for free without requiring any credit to the departed customers who previously paid for those RECs). In other words, the engine driving PG&E's RPS strategy is a valuation approach that violates state law and Commission precedent

---

8 D.22-12-044, at OP1; D.23-12-022, at OP5; D.24-12-038, at COL1.

9 *See* CalCCA Opening Brief, at 34-36.

10 D.24-12-035, *Decision on 2024 Renewables Portfolio Standard Procurement Plans*, R.24-01-017 (Dec. 19, 2024), at 27 ("PG&E plans to meet the RPS compliance requirement by continuing to use banked resources[.]").

11 PG&E Opening Brief, at 35.

because it allows bundled customers to use RECs for RPS compliance without conveying any value of those RECs to the departed customers who paid for the RECs. Thus, in the context of the zero-sum PCIA framework, PG&E's RPS strategy is not an "affordability" measure at all, it is simply a cost-shift to departed load. Any affordability improvement for bundled customers comes with a corresponding affordability worsening for departed customers—a dynamic that is particularly concerning in light of the massive PCIA rate increases PG&E forecasts in its October Update, with rates for several vintages increasing over 6 cents per kilowatt-hour.[12]

Here is how PG&E's RPS strategy works. In its 2024 RPS Plan, PG&E sought and received approval to sell RPS products from its bundled customer Voluntary Allocation.[13] Using that authority, PG&E seeks to sell itself short in the forecast year, including by selling from PG&E's bundled customer Voluntary Allocation and retaining the revenues for bundled customers.[14] PG&E can afford to sell itself short because it can backfill its RPS compliance shortfall using banked RECs. However, this strategy hinges on PG&E using banked RECs without any credit to the departed customers who helped pay for those RECs when they were initially generated and retained. As PG&E explains in Opening Brief:

> Specifically, "[t]he risk is, in some cases, PG&E could sell RPS energy at a lower price than the credit to the PCIA ratemaking account for the pre-2019 banked RECs. For example, if the RPS market price benchmark was $70 per megawatt-hour (MWh) for 2025 and RPS energy prices in the market were as low as mid-$20s/MWh pursuing this alternative sales strategy is more risky and

---

[12] Making matters worse, PCIA rates for departed customers in PG&E's October Update are understated, because the Portfolio Allocation Balancing Account (PABA) balance reflected in PG&E's October Update included $217 million in erroneous duplicate credits. Correcting that error, as PG&E has proposed to do via an errata to its October Update testimony, will result in a further increase to the PCIA revenue requirement. *See* Motion of Pacific Gas and Electric Company (U 39 E) for Leave to File Fall Update Errata, at 2 (Oct. 22, 2025).

[13] D.24-12-035, at 30-31.

[14] PG&E Opening Brief, at 35.

> would cost customers more on a net basis than simply retaining the current RPS deliveries to meet compliance."[15]

In short, PG&E's plan boils down to this: squeeze departed customers by selling PG&E's RPS Allocation at prices lower than the benchmark and backfilling from PG&E's pre-2019 bank without providing value to departed customers that paid for those RECs.

While PG&E is authorized to sell RPS products from its bundled customer Voluntary Allocation and to use banked RECs to cover any shortfall towards its Minimum Retained RPS obligation, assigning pre-2019 banked RECs zero value violates Section 366.2(g) of the Public Utilities Code. That statute requires PG&E provide departed customers the value of any benefits associated with PG&E's PCIA resources that remain with bundled service customers. PG&E's proposal violates Section 366.2(g) because, as PG&E's witness admitted during hearing, the departed customers who previously paid for a portion of the banked RECs neither benefit from the retirement of the banked RECs nor ever receive a credit for PG&E's use of those banked RECs towards bundled customer compliance. This outcome plainly violates Section 366.2(g). As the Commission recently noted in its Decision resolving Track One of the PCIA Rulemaking: "The departed customer is also entitled to any residual procurement benefits enjoyed by the incumbent IOU attributable to the departed customer. The Public Utilities Code and existing policy mandate processes and mechanisms that ensure these costs and benefits are retained by the departing customers, promoting fairness and indifference to all customers."[16]

Further, PG&E's proposal violates the settled indifference framework the Commission has established over the past two decades via its decisions applying the law, including decisions

---

15 PG&E Opening Brief, at 36 (citing Exh. PGE-04 at 4-18).

16 D.25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark*, R.25-02-005 (June 27, 2025), at 2-3.

addressing the RPS value of the IOUs' portfolios beginning with D.11-12-018. The indifference framework requires PG&E to value RECs used by bundled customers at the RPS market price benchmark (MPB) when calculating PCIA rates. Decision 19-10-001 introduced several changes to the PCIA framework, but left intact an important piece of the settled indifference framework: if RECs are retired on bundled customers' behalf, departed customers must receive value for those benefits retained by bundled customers, via a credit to the PCIA at the RPS Adder.

PG&E dismisses Section 366.2(g) and the indifference framework and insists valuing pre-2019 banked RECs would conflict with Commission decisions approving PG&E's RPS strategies. PG&E is wrong because while Commission decisions approving PG&E's RPS sales and procurement activities acknowledge PG&E's massive REC bank, nothing in those decisions authorizes PG&E to use that REC bank <u>without a credit to departed load</u>.

As mentioned above, D.24-12-035 (the Decision approving PG&E's 2024 RPS Plan) approves PG&E's proposal to sell RPS products from its bundled customers' Voluntary Allocation, and approves a strategy that involves using banked RECs towards bundled customer compliance. But nothing in D.24-12-035 permits PG&E to violate the indifference principle and use banked RECs without conveying the credits required by state law. Importantly, nothing in that decision supports the proposition that banked RECs must be assigned zero value in order for PG&E to use those RECs as a part of its RPS strategy. On the contrary, the Commission has recognized that PG&E's voluminous REC bank is helpful insulation for bundled customers from volatility in the RPS market. In D.25-08-009, for instance, the Commission states: "it is uncertain that in the venues for the IOUs to procure or sell RECs (i.e., RPS solicitations for short-term contracts, other solicitations to pursue short-term RECs, bilateral transactions, etc.) bundled customers would not incur higher costs due to unpredictable market conditions."[17] In other words, while the use of banked RECs comes with a cost for bundled customers, those RECs are a helpful hedge against volatile market conditions. The bottom line is, PG&E may sell RPS products from its Voluntary Allocation and apply banked RECs towards its Minimum Retained RPS requirement, but must provide a credit to the departed customers to the extent they paid for a share of those banked RECs when they were originally generated. That outcome squares D.24-12-035, Section 366.2(g), and the Commission decisions addressing the RPS value of the IOUs' portfolios beginning with D.11-12-018.

PG&E insists it must be permitted to use pre-2019 banked RECs without assigning those RECs value because, according to PG&E, the Commission has denied PG&E incremental RPS procurement opportunities including the authority to engage in short-term RPS procurements to mitigate the risk of high MPBs.[18] In fact, the opposite is true. Decision 24-12-035 <u>grants</u> PG&E's request to enter into short-term RPS procurement.[19] It <u>grants</u> PG&E's request to transact bilaterally for the purchase and sale of short and long-term RPS products, enabling PG&E to transact swiftly.[20] It <u>grants</u> PG&E authority to procure short-term and long-term RPS resources and conduct short-term RPS sales by participating in other market participants' competitive solicitations.[21] And it <u>grants</u> PG&E authority to procure short-term and long-term contracts and

---

17 D.25-08-009, *Decision Denying Request to Adopt a Framework for Pre-Approval of Investor-Owned Utilities' Short-Term Renewable Portfolio Standard Transactions*, R.24-01-017 (Aug. 14, 2025), at 17.

18 PG&E Opening Brief, at 37-38.

19 D.24-12-035, at 30.

20 *Id.,* at 31-32.

21 *Id.,* at 33.

sell short-term contracts via brokers and exchanges.[22] The idea that PG&E must use banked RECs without providing value to all customers who paid for them because they cannot access short-term RPS markets is entirely unsupported.

To the extent PG&E believes it needs more streamlined access to short-term RPS market transactions in order to manage its RPS portfolio in its customers' best interests, it should pursue changes to its RPS strategy in a separate proceeding, not in this ERRA proceeding. As PG&E's own witness points out: "R.24-01-017 [the RPS Rulemaking], and not this proceeding, should be the appropriate venue to consider PG&E's RPS compliance and sales strategies."[23] Alternatively, PG&E will have the opportunity to make its case to the Commission in the Integrated Resource Planning (IRP) proceeding, Rulemaking 25-06-019. Per a recent scoping ruling, the scope of that proceeding includes "Updates to Investor-Owned Utility Bundled Procurement Plans."[24] The scoping ruling goes on to specify these Bundled Procurement Plan (BPP) updates "may also include proposals for oversight processes for short-term renewables portfolio standard (RPS) transactions."[25] PG&E may pursue changes to the processes that guide its RPS sales and procurement activities in that proceeding. But the Commission should not permit PG&E to violate Section 366.2(g) and use departed customers as mere levers in a broader utility-friendly RPS strategy. It should reject PG&E's proposal to use pre-2019 banked RECs without a credit to departed load and adopt CalCCA's recommended methodology for valuing pre-2019 banked RECs.

---

22 *Id*.

23 Exhibit PGE-04, at 4-17.

24 *Assigned Commissioner's Scoping Memo and Ruling*, R.25-06-019 (Oct. 28, 2025), at 9.

25 *Ibid*.

B. CREDITING PRE-2019 BANKED RECS IS SOUND POLICY AND PG&E'S ARGUMENTS OPPOSING THAT POLICY ARE MERITLESS

While PG&E's opposition to the pre-2019 banked REC valuation methodology is a little difficult to follow, it includes five discernible arguments. Each is meritless.

First, PG&E argues pre-2019 banked RECs were "fully valued" under the PCIA methodology that remained in place until 2018 and should not be trued-up because the PCIA methodology in place when those RECs were banked did not include a true-up.[26] The Commission should dismiss this sleight of hand. No party disputes pre-2019 banked RECs were paid for at the then-applicable RPS Adder when they were generated, nor that a credit corresponding to the value of those RECs was conveyed to customers who had already departed PG&E's bundled service at the time ("then-departed" customers) via a reduction to the indifference amount.[27] But the fact that those RECs were "fully valued" when generated renders no benefit to customers who departed PG&E's bundled service *after* the RECs were generated ("now-departed customers"). That is because the RECs were never retired on those then-bundled, now-departed customers' behalf, and those customers never received a credit for the value of the RECs through the PCIA.[28] From the perspective of then-bundled, now-departed customers, pre-2019 banked RECs were never "fully valued." Those customers paid for the RECs via their generation rates when they were bundled customers but have yet to receive value for those RECs.

Importantly, conveying value to those now-departed customers is not tantamount to a true-up. A true-up would involve comparing the 2026 RPS Adder to the RPS Adder in effect when the pre-2019 banked REC was generated and returning the delta to customers who had previously

---

26 PG&E Opening Brief, at 30.

27 *See* Exhibit CalCCA-14; Evidentiary Hearing Tr. Vol. 1, at 91.

28 Exhibit CalCCA-15.

received a credit for those banked RECs (*i.e.*, then-departed customers). CalCCA's proposed methodology does not involve any credit or debit to then-departed customers and therefore does not require a "true-up." Rather, it requires pre-2019 banked RECs be valued at the MPB in the year they are used towards bundled customer RPS compliance, which is consistent with the way Retained RPS has been valued for nearly the last fifteen years, since D.11-12-018.

Second, PG&E argues that valuing pre-2019 banked RECs would mean that bundled customers incur a cost increase as a result of departed load, in violation of the indifference principle and Sections 365.2 and 366.3.[29] But PG&E is mistaken—no bundled customer will experience a "cost increase" as a result of CalCCA's methodology. Take, for example, the customers who paid for RECs banked and generated in 2015. Customers who were bundled in 2015 would have paid for those RECs through their generation rates when the RECs were originally valued and retained. Assume Ben was one such bundled customer, and assume Ben remains bundled in 2026. In 2026, when PG&E uses the 2015 REC for RPS compliance, Ben finally receives value for the REC he paid for eleven years prior when PG&E retires the REC on his behalf. Per CalCCA's pre-2019 banked REC valuation methodology, Ben would pay for the 2015 banked REC at the 2026 RPS Adder, but he would <u>also receive an offsetting credit</u> at the 2026 Adder—thereby experiencing <u>no cost increase.</u> In other words, Ben's net cost for the 2015 REC would remain the payment he made for that REC in 2015. Thus, CalCCA's methodology poses no risk of the Commission violating Sections 365.2 or 366.3, which require bundled customers remain indifferent to load departures.

Third, PG&E argues that valuing pre-2019 banked RECs would result in a refund that violates PG&E's tariffs.[30] This argument is hollow. As CalCCA explained in its Opening Brief,

---

[29] PG&E Opening Brief, at 30-31.

[30] *Id.*, at 33-34.

PG&E has previously credited pre-2019 banked RECs when used for compliance. And even in this case, PG&E proposes to use post-2019 banked RECs and credit PCIA vintages corresponding to the year in which those RECs were generated, at the Forecast Adder (just as it has done in prior years). Neither those credits, nor credits to pre-2019 vintages, constitute a "refund" or violate any PG&E tariff.

Fourth, PG&E suggests the Commission has endorsed assigning pre-2019 banked RECs zero value in SCE's prior ERRA Forecast decisions as well as in D.24-08-004, resolving SCE's Petition for Modification of D.23-06-006.[31] PG&E mischaracterizes those decisions. First, the decisions resolving SCE's prior ERRA Forecast cases include language clearly limiting the applicability of the Commission's banked REC conclusions in those cases. The Decision resolving SCE's 2024 ERRA Forecast case, D.23-11-094, for instance, directs SCE to value pre-2019 banked RECs at zero dollars as an "interim solution."[32] Moreover, that Decision explicitly recognizes that the issue could not be "appropriately addressed in a single IOU's ERRA Forecast application.[33] The Commission was similarly careful to limit the applicability of its banked-REC conclusion in the Decision resolving SCE's 2025 ERRA Forecast case, D.24-12-039. That Decision permits SCE to value pre-2019 banked RECs at zero dollars "for this proceeding", *i.e.*, for the purposes of SCE's 2025 ERRA Forecast, and nothing more.[34]

---

[31] *Id*., at 34.

[32] D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast*, A.23-06-001 (Nov. 30, 2023), at 60.

[33] *Id*.

[34] D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.24-05-007 (Dec. 19, 2024), at 68.

Additionally, D.24-08-004, resolving SCE's Petition for Modification of D.23-06-006, does not support PG&E's proposed methodology. That Decision expressly disagreed with SCE's PFM, stating: "SCE did not provide a sufficient justification for modifying D.23-06-006 to specify how D.19-10-001 should apply to RECs that were generated or banked prior to 2019."[35] Further, the Decision punted the question of the proper valuation of pre-2019 banked RECs, stating: "While we recognize that parties have different perspectives about the direction in D.19-10-001 and its applicability to pre-2019 RECs, we do not have the record to evaluate them here fully. We may consider the issue in a future Rulemaking."[36] Thus, PG&E is incorrect in suggesting that D.24-08-004 supports its proposal to deny departed customers the value of pre-2019 banked RECs.

Finally, PG&E argues that valuing pre-2019 banked RECs would conflict with its RPS strategy. But, as explained in detail above, whereas the Commission has authorized PG&E to use its massive REC bank to meet bundled customer RPS compliance requirements, the Commission has not authorized PG&E to violate Section 366.2(g) or the Commission's indifference framework. PG&E may insist that its RPS strategy hinges on its ability to violate the law, but if that is the case, PG&E should pursue changes to its RPS strategy in the IRP or RPS proceedings—not seek a pass in its ERRA proceeding. The Commission should therefore direct PG&E to value all banked RECs, including pre-2019 banked RECs, at the applicable Forecast Adder in the year in which those RECs are used towards bundled customer RPS compliance, and credit the PCIA vintage corresponding to the year the RECs were generated and banked.

---

[35] D.24-08-004, *Decision Denying Petition for Modification of D.23-06-006*, R.17-06-026 (Aug. 2, 2024), at 5.

[36] *Ibid*.

II. PG&E'S RA SOD PROPOSAL IS AN UNWORKABLE SOLUTION TO AN ILL-DEFINED PROBLEM

No party disputes the Commission's implementation of the SoD framework for RA program compliance may require adjustments to the IOUs' valuation of RA in the PCIA framework. Those adjustments may include modifications to RA quantity, RA price, or a combination of the two. In order to develop evidence-based, durable conclusions on how the three IOUs should value RA in the PCIA framework in light of SoD implementation, the Commission should allow parties an opportunity to conduct further analysis and make proposals in the PCIA Rulemaking. Indeed, it appears parties will have this opportunity, because the preliminary scope of Track Two in the PCIA Rulemaking specifically includes the following issue: "Consideration of the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the Slice of Day framework, as was raised in the 2025 ERRA forecast."[37] Until the PCIA Rulemaking resolves that issue, the Commission should direct PG&E to maintain its existing approach to RA valuation.

PG&E, however, is unwilling to wait for the resolution of Track Two in the PCIA Rulemaking and asks the Commission to adopt an "interim solution" here. However, the RA valuation methodologies PG&E offers in this proceeding are unworkable, hasty solutions to an ill-defined problem.

The trajectory of PG&E's RA valuation proposals in this proceeding illustrates just how muddled PG&E's thinking on this issue is. In its direct testimony, PG&E offered a valuation methodology that would have resulted in absurd results by assigning its battery storage resources

---

[37] *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Feb. 20, 2025), at 24.

a near-zero RA quantity (and therefore, a near-zero RA value).[38] In rebuttal testimony, PG&E substantially revised its proposal, now assigning batteries approximately [redacted] of the RA value of baseload resources, but simultaneously slashing the RA value of solar resources.[39] At the evidentiary hearing, PG&E's witness declined to support PG&E's revised methodology as superior to its original proposal, instead calling that revised methodology a "compromise" with CalCCA.[40] In Opening Briefs, PG&E appears to abandon its original proposal and asks the Commission to adopt its revised SoD methodology.[41]

The calculation of the RA value of PG&E's PCIA portfolio is far too consequential an issue for the Commission to approve a hasty proposal offered at the eleventh hour of this proceeding as a "compromise." PG&E's proposals—both original and revised—would result in an increase to the PCIA revenue requirement of [redacted].[42] Impacts of that magnitude do not permit an "act now, think later" approach—especially in light of the already massive rate increases departed customers will bear in 2026, based on PG&E's October Update.

Instead, the Commission should permit parties to rigorously investigate the impacts of SoD on the PCIA framework in Track Two of the PCIA Rulemaking and then implement necessary modifications to the PCIA framework in subsequent ERRA Forecast cases. San Diego Gas & Electric Company (SDG&E) has sensibly taken this approach and will not make changes to RA

---

38 *See* CalCCA Opening Brief, at 52.

39 *Id.*, at 67.

40 Evidentiary Hearing Tr. Vol. 1, at 50.

41 PG&E Opening Brief, at 38.

42 *See* CalCCA Opening Brief, at 3.

valuation for PCIA purposes until the Commission issues a decision addressing the impact of SoD on the PCIA framework.[43]

To the extent the Commission adopts an "interim" solution, however, it should direct PG&E to implement SCE's interim SoD method. That method is superior to PG&E's RA SoD proposals for two reasons. First, it results in storage being valued at approximately 79 percent of baseload resources, which aligns closely with the discount [redacted]. Second, unlike PG&E's revised RA SoD proposal, which varies the RA value of battery resources based on the LSE's optimized dispatch of those resources, SCE's method would produce the same discount for battery storage RA (relative to baseload) if applied to any LSE. This result makes sense in the context of the PCIA, where the objective is to determine the market value of RA from storage resources—that value should not vary based on the manner in which PG&E optimizes the batteries.

Again, the most reasonable path forward here is for the Commission to direct PG&E to maintain the status quo with respect to RA Valuation, until this issue gets the scrutiny it deserves in the PCIA Rulemaking. However, to the extent the Commission is inclined to modify PG&E's RA valuation methodology in this proceeding, the Commission should adopt SCE's interim method. Doing so would apparently satisfy PG&E's objective—during the evidentiary hearing, witness Keller conceded PG&E's objective is to depart from the status quo, and there are multiple potential "right answers" here:

> Q: (CalCCA Counsel) [. . .] So PG&E doesn't want to stick with the status quo, but believes that it needs a methodology adopted in this proceeding that would reflect the Slice of Day RA compliance framework; correct?

---

43 *Id.*, at 70, fn. 275.

```
A:(PG&E Witness Keller)  Yes.

Q:   And PG&E believes there's many different
ways to achieve that objective; is that right?

A:   Yes. Confirming that there are multiple
methodologies that could be developed to come
up with the outcome of the one quantity that's
needed to apply to the RA Adder.[44]
```

Accordingly, to the extent the Commission believes it must adopt an interim solution for RA valuation that departs from the status quo, it should not adopt PG&E's revised RA SoD proposal and should adopt SCE's interim SoD method.

A. PG&E'S REVISED RA SOD METHODOLOGY RESULTS IN UNJUSTIFIED SWINGS IN THE RA VALUE OF ITS BATTERY RESOURCES

PG&E asserts its revised RA SoD methodology "is fully consistent with D.19-10-001's direction that Retained RA be based on PG&E's forecasted retained use."[45] But PG&E's revised RA SoD methodology is heavily predicated on its optimized dispatch of its battery resources, and in particular, on the optimized dispatch in the CAISO peak hour. That not only means PG&E's methodology would produce a different discount for battery value (relative to baseload value) if applied by a different LSE,[46] it also means PG&E's methodology could produce a different volume of battery storage RA in the CAISO peak hour (and accordingly, a different discount for battery value) <u>every time PG&E re-runs its dispatch optimization</u>.

---

44 Evidentiary Hearing Tr. Vol. 1, at 52.

45 PG&E Opening Brief, at 42.

46 *See* Exhibit CalCCA-06C; Evidentiary Hearing Tr. Vol. 1, at 70-71 (witness Keller acknowledging that PG&E's methodology, if applied by a different IOU, could produce a different discount for battery value relative to baseload resources).

Indeed, the battery storage RA in the CAISO peak hour is [redacted] lower in PG&E's October Update relative to the optimized dispatch used to support PG&E's direct and rebuttal testimony (despite PG&E adding one new battery resource in the October Update). Applying the RA MPB to that volume reduction results in a [redacted] lower Retained RA value, even though PG&E needs the <u>same battery resources</u> to meet its RA requirement. Translating those numbers to a discount to baseload: whereas PG&E calculates battery RA value as roughly [redacted] of baseload value in its rebuttal testimony (based on RA optimization conducted for its May testimony filing), that discount drops to approximately [redacted] based on a relatively modest change to PG&E's RA optimization conducted for PG&E's October Update testimony. This substantial swing in Retained RA value—based solely on a modest difference in the battery discharge quantity appearing in the CAISO peak hour at the moment in time the modeling was completed—is illogical in the context of the PCIA. In the PCIA framework, the objective is to come up with a value for PG&E's battery resources that is reasonably representative of those resources' value in the market. If PG&E were to sell its batteries in the market, it would not expect the value of those batteries to vary based on its dispatch of those resources; rather, market value would be broadly driven by all sellers' and buyers' need for those batteries. SCE's Interim SoD method appropriately reflects this intuition—it produces the same discount for battery storage RA (relative to baseload) if applied to any LSE, and irrespective of any individual LSE's dispatch optimization decisions. Therefore, the Commission should not adopt PG&E's revised RA valuation proposal and should adopt SCE's Interim SoD method to the extent it declines to maintain the status quo.

B. PG&E'S REVISED RA SOD METHODOLOGY DOES NOT ALIGN WITH PG&E'S VALUATION OF BATTERY RESOURCES

In its Opening Brief, PG&E claims the discount in the price per Net Qualifying Capacity (NQC) for battery resources reflected in its revised RA SoD proposal is "aligned with PG&E's

most recent forward price curves[.]"[47] That claim does not withstand scrutiny. PG&E's most recent forward price curves, included in Exhibit CalCCA-06C, [redacted] Thus, the record contradicts PG&E's

PG&E's <u>actual</u> storage procurement activity reveals a different story. As CalCCA explained in its Opening Brief, PG&E recently sought Commission approval of a power purchase agreement for long-term RA from an 80 megawatt (MW), four-hour duration standalone battery storage facility (Pastoria) in Advice Letter (AL) 7602-E.[52] [redacted] Thus, the record contradicts PG&E's claim that its revised RA valuation proposal reflects either the "observed market valuation" or

---

47 PG&E Opening Brief, at 44.

48 Evidentiary Hearing Tr. Vol. 1, at 60.

49 *Id.*, at 61.

50 Exhibit CalCCA-06C; Evidentiary Hearing Tr. Vol. 1, at 61-62.

51 Exhibit CalCCA-06C; Evidentiary Hearing Tr. Vol. 1, at 61.

52 *See* CalCCA Opening Brief, at 65.

53 *See id.*, at 67; Evidentiary Hearing Tr. Vol. 1, at 67.

PG&E's valuation of battery resources. In fact, PG&E's valuation of battery resources reflects a discount that is far more closely aligned with the discount produced by SCE's interim SoD method.

C. PG&E HAS ALL THE INFORMATION IT NEEDS TO IMPLEMENT SCE'S INTERIM SOD METHOD IF THE COMMISSION DIRECTS IT TO DO SO

PG&E claims it cannot implement SCE's interim SoD method because CalCCA provided "scant information" regarding that method. That argument not only strains belief, it is also plainly contradicted by the record. First, nothing prevents the Commission from directing PG&E to adopt a methodology approved for another utility in a separate decision. Indeed, just last year, the Commission directed SDG&E to adopt SCE's common cost allocation methodology in SDG&E's ERRA Forecast case, despite lacking any record on SCE's methodology in the SDG&E proceeding.[54]

Second, CalCCA witness Dickman laid out the mechanics of SCE's interim SoD method in his testimony in detail. As Mr. Dickman described:

> According to the SCE Interim SOD Method, baseload resources that deliver consistent output throughout the day continue to count up to their NQC for the month. For intermittent resources (e.g., wind, solar), the RA quantity is the average of their hourly exceedance values, which vary depending on the region and technology. Stand-alone battery storage resources are calculated as the storage NQC minus an estimate of the RA capacity needed for charging. SCE's formula for calculating the RA quantity from storage resources is NQC — NQC * 4 / 24 / Round Trip Efficiency.

Mr. Dickman also quoted directly from SCE's 2026 ERRA Forecast testimony, in which SCE further described its method:

> In the SOD framework, storage resources are not assigned specific pre-determined hourly quantities for the hourly capacity

---

[54] D.24-12-040, *Decision Approving San Diego Gas & Electric Company's 2025 Electric Procurement Revenue Requirement Forecasts, 2025 Electric Sales Forecast, and Greenhouse Gas Related Forecasts,* A.24-05-010 (Dec. 19, 2024), at COL 17.

> 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.[55]

To the extent PG&E needed clarification on any aspect of SCE's Interim SoD method following its review of CalCCA's testimony, it could have conducted discovery—but it chose not to do so. The reality is, PG&E has the information it needs to implement SCE's interim SoD method. To the extent the Commission adopts any change to PG&E's existing RA valuation approach in this proceeding, it should adopt SCE's interim SoD method.

III. CALCCA'S RECOMMENDATIONS RELATING TO ITS NOW-DENIED APPLICATION FOR REHEARING OF D.25-06-049 ARE MOOT

CalCCA's Opening Brief discussed the approach the Commission should have taken on account of CalCCA's Application for Rehearing (AFR) of D.25-06-049 pending. The Commission has since denied that AFR.[56] As a result, those recommendations are moot.

---

55 Exhibit CalCCA-01C, at 30-31 (citing A.25-05-008, SCE-01 at 132:10-21).

56 D.25-10-061.

IV. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission adopt the recommendations listed in the Summary of Recommendations and Conclusions provided in CalCCA's Opening Brief.

November 3, 2025

Respectfully submitted,

Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com

Counsel for CALIFORNIA COMMUNITY CHOICE ASSOCIATION

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

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

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

Utility type:

- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Wade Stano
Phone #: 415-464-6024
E-mail: wstano@mcecleanenergy.org
E-mail Disposition Notice to: wstano@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric
GAS = Gas
WATER = Water
PLC = Pipeline
HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

November 04, 2025.

Advice Letter (AL) #: 91-E

Tier Designation: 2

Subject of AL: RE: Marin Clean Energy's Energy Efficiency Mid-Cycle Advice Letter

Keywords (choose from CPUC listing): Energy Efficiency;

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-05-041; D.21-05-031; D.23-06-055

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

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

Confidential treatment requested? ☐ Yes ☑ No

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

Resolution required? ☐ Yes ☑ No

Requested effective date: 12/4/25

No. of tariff sheets: 0

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

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

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

Tariff schedules affected: N/A

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

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

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

Clear Form

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

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

Contact Name: Wade Stano
Title: Senior Policy Counsel
Utility/Entity Name: Marin Clean Energy (MCE)

Telephone (xxx) xxx-xxxx: 415-464-6024
Facsimile (xxx) xxx-xxxx:
Email: wstano@mcecleanenergy.org

Contact Name: Alice Havenar-Daughton
Title: VP of Customer Programs
Utility/Entity Name: Marin Clean Energy (MCE)

Telephone (xxx) xxx-xxxx: (925) 378-6730
Facsimile (xxx) xxx-xxxx:
Email: ahavenar-daughton@mcecleanenergy.org

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

Clear Form

ENERGY Advice Letter Keywords

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

Clear Form

November 04, 2025

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

MCE Advice Letter 91-E

RE: Marin Clean Energy's Energy Efficiency 2024-2027 Mid-Cycle Advice Letter

I. PURPOSE

Pursuant to Decision ("D.") D.21-05-031 *Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process*, D.23-06-055 *Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2028-2031*; D.25-08-034 *Adopting Energy Efficiency Goals for 2026-2037* and guidance issued from the California Public Utilities Commission ("CPUC" or "Commission"), Marin Clean Energy ("MCE") hereby submits the following Advice Letter ("AL" or "MCAL") to update the technical inputs, forecasts, and related information for its 2024-2027 energy efficiency ("EE") portfolio. MCE additionally includes its request to launch the Multifamily Energy Savings Resource ("MFES-R") program. MCE respectfully submits these collective requests as MCE AL 91-E.

II. TIER DESIGNATION

This AL has a Tier 2 designation pursuant to Ordering Paragraph ("OP") 10 of D.21-05-031.

III. EFFECTIVE DATE

Pursuant to G.O. 96-B; D.21-05-031; and D.23-06-055, MCE respectfully requests that this Tier 2 AL be approved pending Energy Division disposition effective December 04, 2025, 30 days from the date filed.

IV. BACKGROUND

MCE has administered Energy Efficiency ("EE") funds under California Public Utilities Code ("Code") Section 381.1(a)-(d) since 2013. Pursuant to D.21-05-031, MCE filed its *Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan* ("Application") with the Commission pursuant to Article 2 of its Rules of Practice and Procedure, California Public Utilities Code § 381.1 and D. 21-05-031 on March 04, 2022. On July 3rd, 2023, the Commission issued D.23-06-055 approving MCE's

Application and MCE's proposed EE portfolio for Program Years ("PYs") 2024-2027.[1] The Commission approved a four-year budget cap of $78,217,316 for MCE.[2] D.23-06-055 specifically approved all of MCE's proposed programs except for its PeakFLEXmarket program.[3] MCE filed its True-Up Advice Letter ("MCE AL 70-E" or "2023 TUAL") pursuant to D.23-06-055 on October 16, 2023, and submitted additional details on its EE program budgets and portfolio consistent with Energy Division guidance.[4] The CPUC accepted MCE AL 70-E approving its proposed budget amount of $76,670,990 for PYs 2024-2027, and portfolio details in a Disposition with the effective date of November 15, 2023.

On December 28, 2023, Energy Division served *Energy Division Guidance on Integrated Demand-Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs)* to interested parties of the Application ("A.") 22-02-005 et al service list detailing further direction on IDSM AL filings. The guidance directs PAs to propose "specific programs or propose the framework and structure for future multi-DER programs" and includes a template of questions.[5] MCE submitted its IDSM Tier 3 AL, MCE AL 74-E, pursuant to D.23-06-055; and guidance issued by the Commission on December 28, on March 15, 2024. In MCE AL 74-E, MCE requested approval of its proposed IDSM program, the Peak Flex Market program, for PYs 2024-2027. On September 23rd, 2025, the Commission issued Resolution E-5387 approving MCE AL 74-E and its Peak Flex Market program.[6]

On June 24, 2024, MCE submitted MCE AL 77-E RE: Notice of Marin Clean Energy's Small Business Energy Advantage ("SBEA") Program Launch pursuant to D.21-05-031 and *ENERGY DIVISION PROCESS CHECKLIST TO ENERGY EFFICIENCY PROGRAM ADMINISTRATORS FOR PROGRAM CLOSURES AND LAUNCHES (12/31/2021)*. In MCE AL 77-E, MCE notified the Commission of its request to launch the SBEA program within its Equity segment to serve historically underserved businesses in environmental and social justice ("ESJ") communities.[7] On July 24, 2024, the Commission approved MCE AL 77-E and its SBEA program.

On August 24, 2025, Commission Executive Director Rachel Peterson granted an extension until 60 days after the issuance date of the decision adopting energy efficiency goals for MCALs in compliance with OP 10 in D.21-05-031.[8] On September 5, 2025, the Commission issued D.25-08-034 Adopting Energy Efficiency Goals for 2026-2037.

---

[1] *See* D.23-06-055 at p. 93 (Table 7).
[2] *Id*.
[3] D.23-06-055 at pp. 103 (approving all non-discussed programs), 104-105 (stating general support for Peak FLEXmarket's approach, but failing to authorize additional funding).
[4] MCE AL 70-E, pp. 12-13 (updating the Commercial Equity program ID to MCE02e).
[5] Energy Division Guidance on Integrated Demand-Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs), December 2023, at pp. 2, 5.
[6] CPUC, E-5387, pp. 1, A-32 - A-35.
[7] MCE AL 77-E, pp. 2-5 (program description).
[8] CPUC, RE: Request for Extension of Time to Comply with Decision 21-05-031 Requiring a Tier 2 Mid-Cycle True-Up Advice Letter by September 1, 2025, pp. 1-2.

A. Regulatory Filing Requirements[9]

1. D.21-05-031 *Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process*

   a. MCAL Requirements

   - OP 10 requires each EE PA to file a mid-cycle review (in year two of a four-year portfolio) Tier 2 AL adjusting its "technical inputs, forecasts, and portfolio to account for the changes in energy efficiency potential and goals."[10]
   - Conclusion of Law ("COL") 31 requires: CPUC staff to review MCALs according to Section 5.2.6 of this decision.
   - Section 5.2.6 requires:
     - PAs to update portfolio and savings forecasts and goals.
     - PAs must meet Total System Benefit ("TSB") and Total Resource Cost ("TRC") four-year forecasted goals.
     - PAs must demonstrate Equity and Market Support segments do not collectively exceed 30% of total portfolio budgets.
     - PAs submit a report on progress on metrics relevant to each portfolio segment.[11]

   b. Program Launch Requirements

   - OP 12 requires:
     - All PAs to file a Tier 2 AL when opening a new program or closing an existing program.
     - PAs may include program launch proposals in other Tier 2 ALs that may be filed for other reasons such as budget requests.
     - PAs shall follow the corresponding program launch checklist provided by CPUC staff on its website.[12]

---

[9] CPUC Energy Division staff provided direction in its MCAL Template to address decisions D.21-05-031; D.23-06-055; new potential and goals decision; and "natural gas phase-out #2" in 2025 in this section. At the time of filing, to MCE's knowledge, the CPUC has not yet issued "natural gas phase-out #2" referenced in this template. However, MCE confirms it will comply with any related subsequent decisions.

[10] D.21-05-031, OP 10.

[11] D.21-05-031, pp. 42-43.

[12] D.21-05-031, at pp. 83-84 (OP 12).

2. <u>D.23-06-055</u> *Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2028-2031*

   a. MCAL Requirements

      - OP 1:
        - Approves MCE as a non-IOU EE portfolio administrator.[13]
      - OPs 5-6:
        - Approves MCE's EE portfolio budget of $78,217,316 for PY 2024-2027 and $80,063,445 budget forecast for 2028-2031.[14]
      - OP 16:
        - Requires PAs to include descriptions of how they incorporated or addressed impact evaluations recommendations in 2025 MCAL submissions.[15]
      - OP 23:
        - Requires PAs to work with the Reporting Policy Coordination Group to submit a demographic report on participation in portfolio programs by September 1st, 2025.[16]
      - OP 24:
        - Requires PAs to develop and include community engagement indicators in 2025 MCAL submissions.[17]
      - OP 34:
        - Requires PAs to submit updated Joint Cooperation Memorandums ("JCMs") 60 days following the approval of True-Up or MCAL to the Commission and relevant EE service list.[18]

3. <u>D.25-08-034</u> *Adopting Energy Efficiency Goals for 2026-2037*

   a. Recognizes a request for an MCAL submission extension was submitted and addressed through the appropriate Rule 16.6 of the Commission's Rules of Practice and Procedure process.[19]

   b. OP 1:

      - Updates the TSB and energy savings goals for 2026 – 2037 pursuant to the 2025

---

[13] D.21-05-031, OP 1.
[14] *Id*. at pp. 93-94; OPs 5-6.
[15] *Id*. at OP 16.
[16] *Id*. at OP 23. MCE participated in the Reporting PCG Demographic Data Report which was submitted to the Commission on August 6th, 2025.
[17] *Id*. at OP 24.
[18] *Id*. at OP 35.
[19] D.25-08-034, p. 25.

Potential and Goals Study.[20]

B. Contents of this Filing

The contents of this MCAL are as follows:

- Narrative Document
- Attachment A: *Appendices from Excel Template in PDF*
- Attachment B: *Community Engagement Indicators Results*
- Attachment C: *PA Response to Recommendations*
- Attachment D: *CEDARS Filing Confirmation*
- Attachment E: *MCE Multifamily Energy Savings Resource Program Implementation Plan*; and
- Attachment F: *MCE Multifamily Energy Savings Resource Program Webinar Slides*.

V. DISCUSSION

MCE submits its proposed EE portfolio updates for PYs 2024-2027 in compliance with D.21-05-031, D.23-06-055, D.25-08-034, Energy Division MCAL template, and Commission guidance for Resource Acquisition segment programs.[21]

A. Portfolio Overview

1. Recent CPUC Decisions or Guidance Impacting EE Portfolios

On January 22nd, 2025, the Commission closed Rulemaking (R.) 13-11-005 Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues in D. 25-01-006. In D.25-01-006, the Commission denied the motion of Association of Bay Area Governments and County of Ventura on behalf of Bay Area Regional Energy Network ("BayREN") and Tri-County Regional Energy Network ("3C-REN") on the categorization of all multifamily properties as "hard-to-reach."[22] The Commission noted it may scope multifamily issues and how to better serve multifamily residents in a successor EE proceeding.[23]

On April 29th, 2025, the Commission issued R.25-04-010 the new *Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation* that included a preliminary scope of issues and proposed schedule. On July 23rd, 2025, President Reynolds issued an Assigned Commissioner's Scoping Memo and Ruling with a final scope and proposed schedule for the proceeding. The scope includes oversight of the PYs 2024-2027 portfolios, treatment of

[20] *Id*. at OP 1.
[21] D.21-05-031, p. 14 ("Resource Acquisition: Programs with a primary purpose of, and a short-term ability to, deliver cost-effective avoided cost benefits to the electricity and natural gas systems. Short-term is defined as during the approved budget period for the portfolio, which will be discussed further later in this decision. This segment should make up the bulk of savings to achieve TSB goals."); Application, Exhibit 2, Chapter 3.
[22] D.25-01-006 at p. 11.
[23] *Id*.

multifamily buildings, cost-effectiveness, the Commission's response to Governor Newsom's Executive Order N-5-24 regarding electricity affordability,[24] and other implementation issues.

On June 17th, 2025, the Commission issued Resolution E-5351 approving metrics for the Equity and Market Support segments. In E-5351 the Commission also refines common metrics and related reporting processes across the EE portfolios.[25]

On September 23rd, 2025, the Commission issued Resolution E-5387 approving IDSM programs and frameworks including MCE's Peak Flex Market program.[26] E-5387 outlines IDSM program implementation and reporting requirements.

2. Forecast Approach

MCE rooted its forecast approach in a review of historical program expenditures, commitments, and performance trends, adjusted for anticipated implementation activity and timing over the remainder of the PYs 2024-2027 portfolio cycle. In addition, MCE's forecasts remain aligned with its approved Application by prioritizing the maximization of TSB for its Population Normalized Metered Energy Consumption ("NMEC") Market Access programs, while also fully utilizing its allowable budgets for Market Support and Equity segment programs serving customers that historically faced barriers to accessing EE portfolio programs.

3. Portfolio Changes

This section describes updates MCE has made to its portfolio since submitting its 2023 TUAL, MCE AL 70-E, that are not the result of CPUC guidance or decisions discussed above in **Section IV. A**.

Overall, MCE's portfolio budget and TSB have decreased by approximately 8 percent and 24 percent, respectively. However, this year's filing introduces TSB forecasts for three additional programs, the Multifamily Energy Savings Resource ("MFES-R"), IDSM, and Small Business Energy Advantage ("SBEA") programs, which previously had placeholder budgets without TSB forecasts in MCE's 2023 TUAL[27].

In MCE's 2023 TUAL, MCE adopted a very conservative forecasting approach by excluding a TSB forecast for the SBEA program. Since that filing, MCE successfully launched the SBEA program and includes corresponding TSB forecasts in this MCAL.

---

[24] CPUC, CPUC Response to Executive Order N-5-24, February 18, 2025, at 18, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/reports/cpuc-response-to-executive-order-n-5-24.pdf (requiring analysis of costs and benefits of ratepayer funded programs).
[25] CPUC, E-5351, pp. 5-15.
[26] CPUC, E-5387, pp. 1, A-32 - A-35.
[27] MCE AL 70-E.

On September 23, 2025, the Commission issued Resolution E-5387 approving IDSM programs and frameworks including MCE's Peak Flex Market program. MCE plans to launch its IDSM program in the first quarter of 2026 and incorporates corresponding TSB forecasts in this filing.

MCE made no other material changes to its portfolio beyond those noted above. MCE further discusses additional portfolio details in **Section VI**.

B. Summary of Forecasted Portfolio Impacts

This section presents MCE's summary of forecasted portfolio impacts, including tables summarizing forecasted budgets, TSB, and cost-effectiveness, as requested in the Energy Division's Final Mid-Cycle Advice Letter (MCAL) Excel-based budget filing appendix.

Overall, MCE forecasts the following for the 2024-2027 portfolio period:

- Total portfolio expenditures and forecasts of $70.4 million, including actual 2024 expenditures and forecasted budgets for PYs 2025–2027;
- Achievement of 78 percent of the cumulative TSB goal;
- A TRC ratio of 1.01 and PAC ratio of 1.48; and
- Allocation of approximately 29% of the total portfolio budget to Market Support and Equity segment programs.

1. Portfolio Budget Summary

As shown in *Table 2.3a*, MCE's total portfolio expenditures and forecasts for 2024–2027 amount to $70.4 million. These totals include actual expenditures incurred in 2024 and forecasted expenditures for 2025–2027. The total remains below the Commission's approved 2024–2027 portfolio budget cap of $78,217,316, pursuant to D.23-06-055.[28]

MCE's Market and Equity Support segments represent 29 percent of the total portfolio, as shown in *Table 2.3a*, consistent with the 30 percent portfolio budget cap.[29]

Compared to the $76.7 million cumulative portfolio forecast presented in MCE's 2023 TUAL shown in *Table 2.3b*, the updated forecast is approximately $6 million lower, reflecting adjustments based on actual 2024 spending and updated program pacing assumptions for PYs 2025–2027.

Table 1.5 provides a breakdown of MCE's four-year portfolio by fuel type (electric and gas). The table reflects program funding by fuel type and excludes cost-recovery offsets.

[28] D.23-06-055, pp. 93, 95.
[29] D.21-05-031, pp. 42-43.

Table 2.3a - MCAL Updated Annual and Cumulative Budget

Line	Segment	PY 2024-Actual	PY 2025 TUAL	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 5,329,717	$ 12,667,443	$ 13,475,653	$ 13,475,653	$ 44,948,465
2	Market Support	$ 965,264	$ 982,711	$ 1,081,086	$ 1,081,086	$ 4,110,146
3	Equity	$ 4,272,503	$ 4,775,218	$ 4,850,610	$ 4,850,610	$ 18,748,941
4	Codes and Standards	$ -	$ -	$ -	$ -	$ -
5	EM&V (PA and ED)	$ 204,138	$ 767,724	$ 808,639	$ 808,639	$ 2,589,141
6	**Total Budget w/o OBF Loan Pool**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
7	Market Support and Equity, percent of the Total Portfolio Budget **w/o OBF Loan Pool**					29%
8	OBF Loan Pool Addition	$ -	$ -	$ -	$ -	$ -
9	**Budget excluding Portfolio Oversight**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
10	ED Portfolio Oversight	$ -	$ -	$ -	$ -	$ -
11	**Total Portfolio Budget w/ ED Portfolio Oversight**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
12	**Approved Budget Cap** [4]					**$ 78,217,316**

[4] Decision 23-06-055 OP5

Table 2.3b - TUAL Annual and Cumulative Budget

Line	Segment	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 12,968,308	$ 12,667,443	$ 12,544,743	$ 12,422,359	$ 50,602,854
2	Market Support	$ 975,340	$ 982,711	$ 990,102	$ 997,858	$ 3,946,010
3	Equity	$ 4,919,346	$ 4,775,218	$ 4,712,055	$ 4,648,669	$ 19,055,287
4	Codes and Standards	$ -	$ -	$ -	$ -	$ -
5	EM&V (PA and ED)	$ 785,958	$ 767,724	$ 760,287	$ 752,870	$ 3,066,840
6	**Total Budget w/o OBF Loan Pool**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**
7	Market Support and Equity, percent of the Total Portfolio Budget **w/o OBF Loan Pool**					30%
8	OBF Loan Pool Addition	$ -	$ -	$ -	$ -	$ -
9	**Budget excluding Portfolio Oversight**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**
10	ED Portfolio Oversight	$ -	$ -	$ -	$ -	$ -
11	**Total Portfolio Budget w/ ED Portfolio Oversight**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**

Table 1.5 - 4 Year Funding Sources - RENs/CCAs (RENs/CCAs Only)

Line		PG&E		SDG&E		SCE	SCG
1	Year	Electric $	Gas $	Gas $	Electric $	Electric $	Gas $
2	2024	$ 11,592,881	$ 8,056,070				
3	2025	$ 11,707,788	$ 7,485,307				
4	2026	$ 12,533,912	$ 7,682,075				
5	2027	$ 11,725,273	$ 8,490,715				
6	**Total**	**$ 47,559,854**	**$ 31,714,167**	$ -	$ -	$ -	$ -

2. Total System Benefit Forecast

As shown in *Table 2.1a*, MCE's cumulative TSB forecast for PYs 2024–2027 is $72.45 million, representing 78 percent of MCE's revised cumulative TSB goal of $92.77 million. The total TSB forecast reflects actual TSB achieved in 2024 and forecasted TSB for PYs 2025–2027.

Table 2.1a - MCAL Updated Annual and Cumulative Total System Benefit Forecast

Line	Segment	PY 2024-Actual	PY 2025 TUAL	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 2,488,664	$ 22,662,424	$ 19,569,409	$ 21,490,567	**$ 66,211,064**
2	Market Support	$ -	$ -	$ -	$ -	**$ -**
3	Equity	$ 793,573	$ 1,093,988	$ 2,119,714	$ 2,235,414	**$ 6,242,689**
4	**Total TSB Forecast**	**$ 3,282,237**	**$ 23,756,413**	**$ 21,689,123**	**$ 23,725,981**	**$ 72,453,754**
5	CPUC TSB Goal	$ 23,601,101	$ 23,753,413	$ 21,689,123	$ 23,725,981	$ 92,769,618
6	*TSB Forecast / TSB Goal* [1]	*14%*	*100%*	*100%*	*100%*	*78%*

[1] D.21-09-037 at 24: Non-IOU program administrators may propose to revise their goals and savings forecasts in the true-up or mid-cycle advice letter.

3. Portfolio Cost Effectiveness Forecast

As shown in *Table 3a*, MCE's updated cost-effectiveness forecast for the 2024–2027 portfolio period reflects a TRC ratio of 1.01, a PAC ratio of 1.48, and a Ratepayer Impact Measure ("RIM") ratio of 0.35 for Resource Acquisition programs, indicating overall cost-effective performance. At the portfolio level (excluding Codes and Standards), MCE forecasts a TRC ratio of 0.80, a PAC ratio of 1.04, and a RIM ratio of 0.34. These ratios incorporate 2024 actuals and forecast ratios for PYs 2025-2027.

Table 3a - MCAL Updated Portfolio Cost Effectiveness Ratios (PY 2024-2027)[1]

Line			TRC ratio	PAC ratio	RIM ratio
1	Segment	**Resource Acquisition**	**1.01**	1.48	0.35
2		Market Support	0.00	0.00	0.00
3		Equity	0.37	0.39	0.30
4		Codes and Standards (C&S)	N/A	N/A	N/A
5	Portfolio	*Including* C&S	N/A	N/A	N/A
6		*Excluding* C&S	0.80	1.04	0.34

[1] 2024 Actuals and the 2025 TUAL forecast are used in the updated forecast

4. Statewide and Third-Party Compliance (IOU Only)

This section is not applicable to MCE.

5. Market Support and Equity Forecast

MCE's Market and Equity Support segments represent 29 percent of the total portfolio, as shown in *Table 2.3a* above, consistent with the 30 percent portfolio budget cap.[30]

6. Codes and Standards Savings Forecast (All PAs, as applicable)

This section is not applicable to MCE.

7. Non-Advocacy Codes and Standards Budget Forecast

This section is not applicable to MCE.

VI. ENERGY EFFICIENCY PORTFOLIO DETAILS

A. Segment Metrics

Pursuant to D.18-05-041,[31] MCE has reported sector-level metrics and associated targets for each program year through 2024 in its annual EE Report filings. These reports, including all corresponding metrics, are publicly available on CPUC's CEDARS website.[32]

B. Program Changes

Since MCE's 2023 TUAL, MCE transitioned to new implementers for its Commercial and Residential Efficiency Market Access programs. Additionally, MCE significantly reduced the budgets and TSB forecasts for its Agricultural Strategic Energy Management ("SEM") and

[30] D.21-05-031, pp. 42-43.
[31] D.18-05-041 at OP 11.
[32] CPUC, California Energy Data and Reporting System, available at: https://cedars.cpuc.ca.gov/.

Residential Efficiency Market programs to reflect lower participation levels and limited opportunities for additional savings.

C. New Programs

In this filing, MCE proposes to launch a new Multifamily Energy Savings Resource program in Program Year 2026 to expand energy efficiency offerings for multifamily properties.

MCE followed the *ENERGY DIVISION PROCESS CHECKLIST TO ENERGY EFFICIENCY PROGRAM ADMINISTRATORS FOR PROGRAM CLOSURES AND LAUNCHES (12/31/2021)* provided by Commission staff, including the following requirements:

- MCE notified service lists R.13-11-005, A.22-02-005 et al. and R.25-04-010 of the requested MFES-R program launch on September 9, 2025, at least 45 days prior to the filing of this AL.
- MCE hosted a public webinar soliciting stakeholder feedback on its program launch proposal and providing information on proposed next steps on September 30, 2025, 20 days prior to the filing of this AL.
- MCE posted the MFES-R public webinar slides to the California Energy Efficiency Coordinating Committee ("CAEECC") on October 1, 2025. [33]
- MCE timely filed this AL on November 04, 2025, over 45 days following its notice to required energy efficiency service lists and over 20 days following its public webinar.
- In this AL, MCE details how its MFES-R program aligns with its Application, supports greenhouse gas emissions reductions, advances EE goals, is in the best interest of ratepayers, and incorporates the received stakeholder feedback.

MCE designed the MFES-R program to comply with the Resource Acquisition segment requirements to deliver short-term cost-effective avoided cost benefits to the electricity and natural gas systems.[34] The MFES-R program focuses on high-impact, cost-effective measures that deliver significant energy savings as discussed further below. By focusing on electrification measures that reduce the use of natural gas, the MFES-R program supports progress on the state's greenhouse gas emissions reductions and decarbonization goals and is in the best interest of ratepayers.

The MFES-R program is also consistent with MCE's approved EE portfolio strategies as it:

- Supports electrification and building decarbonization efforts;[35]
- Helps MCE deliver cost-effective savings to priority communities and customers;[36] and

[33] CAEECC, Program Information (e.g., program closures, updates, etc.), available at: https://www.caeecc.org/program-closures.
[34] D.21-05-031, p. 14.
[35] MCE Application, Exhibit 2, Chapter 3, p. 1-11.
[36] *Id*. at p. 3-3.

- Works to maximize TSB.[37]

The MFES-R program aims to advance the following goals and objectives:

- Extend access to electrification incentives beyond deed-restricted affordable properties, reaching more multifamily communities and residents in MCE's service area.
- Support multifamily property owners in initiating electrification through targeted, high-impact measures.
- Provide customized technical assistance to guide projects from initial assessment through construction.
- Reduce market barriers to decarbonization for multifamily residents and properties by bridging the funding gap for electrification retrofits.

The Association for Energy Affordability ("AEA" or "Implementor") a nonprofit organization specializing in EE for new and existing buildings will implement the MFES-R program. AEA presently implements MCE's existing Multifamily Energy Savings ("MFES") program within the Equity segment of its portfolio.

The MFES Resource Program is designed to reduce market barriers that limit electrification adoption in multifamily buildings while applying best practices informed by MCE's experience implementing its MFES Equity segment program. By extending access to all multifamily properties, the program addresses challenges unique to market-rate and mixed-income properties while providing a streamlined, customer-centered approach in the best interest of ratepayers.

The MFES-R program supports a range of electrification measures in both common areas and in-unit applications.

Primary measures incentivized in this program include:

- Heat Pump Water Heating;
- Heat Pump Space Heating & Cooling;
- Induction Ranges & Cooktops;
- Technical Assistance - Each property is assigned a technical assistant to streamline the customer experience and minimize administrative barriers; and
- Comprehensive assessment with targeted measures: Incentives focus on the most cost-effective measures, and assessments identify additional beneficial opportunities and connect owners to other available programs.

Measure Type	Measure	Location
Electrification	Heat Pump Water Heater	In-Unit
Electrification	Heat Pump Water Heater	Common Area

[37] *Id*. at p. 1-10.

Electrification	Ductless Mini Split	In-Unit
Electrification	Heat Pump Water Heater	Central
Electrification	Package Terminal Heat Pump	In-Unit
Electrification	Ducted Heat Pump	Common Area
Electrification	Heat Pump Water Heater	Pool
Electrification	Induction Range	In-Unit

Further program details are available in **Attachment F** to this filing: *MCE Multifamily Energy Savings Program Implementation Plan.*

D. Program Closures

MCE did not close any programs between its 2023 TUAL and this MCAL filing. Presently. MCE does not anticipate any program closures during PYs 2026–2027.

E. EM&V (2024-2027)

As shown in *Table 2.3a* above, the total Evaluation, Measurement, and Verification ("EM&V") budget for MCE's portfolio is $2,589,141, representing approximately 4 percent of the $70,396,693[38] total portfolio amount. MCE proposes a 40/60 cost split between MCE-administered EM&V activities and CPUC-administered EM&V funds for PYs 2026–2027.

F. Cost Recovery, Unspent Funds and Fund Transfers

MCE's unspent and uncommitted funds from PYs 2021 through 2025 are being applied as offsets to its PYs 2024 and 2026 cost recovery requests.

2024 Offset (TUAL):

- MCE reported a total of $12.47 million in unspent and uncommitted funds from PYs 2021–2023.
- MCE incorporated these funds into its 2023 TUAL to offset its PY 2024 cost recovery request.

2026 Offset (MCAL):

- For this MCAL, MCE projects $20.10 million in unspent and uncommitted funds from PYs 2021–2025.
- These funds will offset MCE's 2026 cost recovery request.

In total, $32.57 million in unspent and uncommitted funds are available across PYs 2024–2027 to offset MCE's future budgets and cost recovery requests. This ensures that MCE's spending remains

[38] *See* **Portfolio Budget Summary** discussion at p. 7 of this filing.

below and is compliant with the Commission-authorized portfolio budget and CPUC direction to return unspent funds.[39]

MCE's Unspent and Uncommitted Funds

MCE	2021	2022	2023	2024	2025	2024-2027
MCE Unspent and Uncommitted Funds for 2024 Offset (TUAL)	**($8,216,227)**	**($3,999,799)**	**($253,033)**			**($12,469,059)**
MCE Unspent and Uncommitted Funds for 2026 Offset (MCAL)	**($74,272)**	**($323,172)**	**($5,321,854)**	**($7,644,320)**	**($6,735,056)**	**($20,098,673)**
MCE Total Unspent and Uncommitted Funds	**($8,290,499)**	**($4,322,971)**	**($5,574,887)**	**($7,644,320)**	**($6,735,056)**	**($32,567,733)**

The table below presents MCE's Spending Budget Request for PYs 2024–2027, incorporating adjustments for carryover funding and unspent/uncommitted offsets.

- The Spending Budget Request excluding offsets totals $79.27 million across PYs 2024–2027.
- After accounting for $3.66 million in carryover funding from prior years, MCE's Actual Spending Budget Request including carryover totals $75.61 million in compliance with D.23-06-055.[40]
- After applying unspent and uncommitted funds as offsets, MCE submits the resulting Total Cost Recovery Request of $43.04 million.

It is important to note that the $3.66 million in carryover funding was already incorporated into MCE's 2023 TUAL and, therefore, is not an additional budget request under PYs 2026–2027. MCE included this amount in its 2024 cost-recovery request and is reflected here solely to maintain transparency and continuity in the multi-year budget presentation.

Because the $3.66 million carryover has already been used to offset the 2023 TUAL cost-recovery request, it is not additive to MCE's 2026 MCAL cost-recovery request. In other words, MCE's 2026 spending budget request of approximately $20.2 million already includes the carryover

[39] D.23-06-055 at OP 7 ("For any unspent and uncommitted funds, portfolio administrators shall: (a) use any unspent and uncommitted funds from prior approved portfolio periods, with the exception of funds required to be sent to the California Energy Commission according to Assembly Bill 841 (Stats. 2020, Ch. 372), to offset budget and collection needs during the 2024-2027 portfolio period approved in this decision; and (b) report any funds collected and spent over the four-year portfolio cycle, annually and cumulatively, and any unspent funds applied to offset collections in subsequent years in the annual reports.").

[40] D.23-06-055, pp. 93, 95 (Tables 7 and 9: CPUC authorizing $78,217,316 for MCE's Approved 2024-2027 Budget Cap and $78,217,316 PG&E Revenue Requirement (Collections) REN and CCA Budget by IOU, 2024-2027 for MCE).

funding and does not represent an incremental or new request beyond Commission authorized portfolio funding.

Although MCE's Spending Budget Request displayed below totals $79.27 million, this reflects the revised program cycle after updating the 2026–2027 budget years. Once prior-year carryover is accounted for, the Actual Spending Budget Request of $75.6 million remains below MCE's authorized limit and within the Commission-approved portfolio limit and cost recovery cap of $78,217,316 established under D.23-06-055.[41]

Spending Budget Request

MCE	2024	2025	2026	2027	2024-2027
MCE Spending Budget Request for 2024-2027 Excluding Offset	**$19,648,951**	**$19,193,096**	**$20,215,987**	**$20,215,987**	**$79,274,022**
Carryover Funding for Spending Budget Request & Cost Recovery Offsets			**($3,661,414)**		**($3,661,414)**
MCE Actual Spending Budget Request for 2024-2027 Including Carryover Offset	**$19,648,951**	**$19,193,096**	**$16,554,573**	**$20,215,987**	**$75,612,608**
MCE Unspent and Uncommitted Funds for Offset	**($12,469,059)**		**($20,098,673)**		**($32,567,733)**
MCE Total Cost Recovery Request (including Offset to 2024 & 2026 Cost Recovery)	**$7,179,892**	**$19,193,096**	**($3,544,100)**	**$20,215,987**	**$43,044,874**

The table below provides MCE's requested payment and transfer schedule for the 2026–2027 program years. MCE requests that PG&E provide these payments, allocated between electric and gas budgets, through quarterly transfers as shown, and issue a one-time transfer of the 2026–2027 EM&V budgets by January 15 of each program year.

MCE Requested Payments

Year	Electric Quarterly Transfer	Gas Quarterly Transfer	Quarterly Transfer Subtotal	One-time EM&V MCE Transfer	Annual Total
2026	$1,459,734	$973,156	$2,432,890	$161,727	$9,893,287
2027	$1,459,734	$973,156	$2,432,890	$161,727	$9,893,287

[41] D.23-06-055, pp. 93, 95 (Tables 7 and 9: CPUC authorizing $78,217,316 for MCE's Approved 2024-2027 Budget Cap and $78,217,316 PG&E Revenue Requirement (Collections) REN and CCA Budget by IOU, 2024-2027 for MCE).

H. Integrated Demant-Side Management (IDSM) Budget

Pursuant to D.23-06-055, PAs may allocate up to 2.5 percent, or $4 million, whichever is greater, up to a maximum of $15 million, from their total approved 2024–2027 budgets to fund innovative IDSM projects, including ongoing load-shifting that is not event-based.[42] Pursuant to D.23-06-055 and E-5387 approving its IDSM program, MCE proposes to allocate $3 million from its 2024–2027 portfolio to support IDSM activities in its Peak Flex Market program.

VII. CONCLUSION

MCE respectfully submits MCE AL 91-E to notify the Commission of its 2024-2027 EE portfolio updates and request to launch the MFES-R program.

VIII. NOTICE

MCE served a copy of this AL via email on the official Commission service list for R.13-11-005, A.22-02-005 et al. and R.25-04-010 on November 4, 2025.

For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov or MCE Regulatory at regulatory@mcecleanenergy.org.

IX. PROTESTS

Anyone wishing to protest this advice filing providing updates on MCE's 2024-2027 EE portfolio and proposal to launch MCE's new MFES-R program may do so electronically no later than 20 days after the date of this advice filing on November 24, 2025.

Protests should be addressed to the attention of the Energy Division Tariff Unit:

Email: EDTariffUnit@cpuc.ca.gov.

In addition, protests and all other correspondence regarding this AL should also be sent electronically to the attention of:

Wade Stano
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024x104
Email: wstano@mceCleanEnergy.org

Alice Havenar-Daughton
VP of Customer Programs
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (925) 378-6730
Email: ahavenar-daughton@mceCleanEnergy.org

[42] D.23-06-055 at COL 41 and OP 29.

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

X. CORRESPONDENCE

For questions, please contact Wade Stano at (415) 464-6024 or by electronic mail at wstano@mceCleanEnergy.org.

/s/ Wade Stano

Wade Stano
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
Email: wstano@mceCleanEnergy.org

Appendices
Attachment A: Appendices from Excel Template in PDF[43]
Attachment B: Community Engagement Indicators Results
Attachment C: PA Response to Recommendations
Attachment D: CEDARS Filing Confirmation
Attachment E: *MCE Multifamily Energy Savings Resource Program Implementation Plan*; and
Attachment F: *MCE Multifamily Energy Savings Resource Program Webinar Slides*.
cc: Service List for R.13-11-005; A.22-02-005 et al.; and R.25-04-010.

DATED: November 4, 2025.

[43] *See* CEDARS (https://cedars.cpuc.ca.gov/) for an excel version of *Attachment A*.

Table 1.1a - MCAL Updated Portfolio Budget by Sector and Segment (Cumulative for PY 2024-2027 [1])

Line	Budget Category	Program Segment Resource Acquisition	Market Support	Equity	Codes & Standards	Total
1	Residential Sector	$ 9,304,434	$ -	$ 15,036,695	$ -	$ 24,341,129
2	Commercial Sector	$ 27,752,480	$ -	$ 3,135,083	$ -	$ 30,887,562
3	Industrial Sector	$ 4,305,461	$ -	$ -	$ -	$ 4,305,461
4	Agricultural Sector	$ 1,478,469	$ -	$ -	$ -	$ 1,478,469
5	Public Sector	$ -	$ -	$ -	$ -	$ -
6	Cross Cutting Sector					
7	Emerging Tech	$ -	$ -	$ -	$ -	$ -
8	WE&T	$ -	$ 3,965,003	$ -	$ -	$ 3,965,003
9	Finance	$ -	$ -	$ -	$ -	$ -
10	Codes & Standards	$ -	$ -	$ -	$ -	$ -
11	Portfolio Support	$ 2,107,621	$ 145,143	$ 577,163	$ -	$ 2,829,928
12	OBF Loan Pool					$ -
13	**Portfolio Subtotal [2]**	**$ 44,948,465**	**$ 4,110,146**	**$ 18,748,941**	**$ -**	**$ 67,807,552**

[1] 2024 Actuals and the 2025 TUAL forecast are used in the updated forecast
[2] excludes EM&V and Portfolio Oversight

Table 1.1b - TUAL Portfolio Budget by Sector and Segment (Cumulative for PY 2024-2027 [1])

Line	Budget Category	Program Segment Resource Acquisition	Market Support	Equity	Codes & Standards	Total
1	Residential Sector	$ 11,377,485	$ -	$ 14,933,095	$ -	$ 26,310,579
2	Commercial Sector	$ 33,095,155	$ -	$ 3,660,786	$ -	$ 36,755,941
3	Industrial Sector	$ 3,131,403	$ -	$ -	$ -	$ 3,131,403
4	Agricultural Sector	$ 1,773,410	$ -	$ -	$ -	$ 1,773,410
5	Public Sector	$ -	$ -	$ -	$ -	$ -
6	Cross Cutting Sector					
7	Emerging Tech	$ -	$ -	$ -	$ -	$ -
8	WE&T	$ -	$ 3,850,416	$ -	$ -	$ 3,850,416
9	Finance	$ -	$ -	$ -	$ -	$ -
10	Codes & Standards	$ -	$ -	$ -	$ -	$ -
11	Portfolio Support	$ 1,225,400	$ 95,594	$ 461,406	$ -	$ 1,782,400
12	OBF Loan Pool					$ -
13	**Portfolio Subtotal [2]**	**$ 50,602,854**	**$ 3,946,010**	**$ 19,055,287**	**$ -**	**$ 73,604,151**

[2] excludes EM&V and Portfolio Oversight

Table 1.1c - Change Portfolio Budget by Sector and Segment (Cumulative for PY 2024-2027)

Line	Budget Category	Change-Program Segment Resource Acquisition	Market Support	Equity	Codes & Standards	Total
1	Residential Sector	$ (2,073,051)	$ -	$ 103,600	$ -	$ (1,969,451)
2	Commercial Sector	$ (5,342,675)	$ -	$ (525,704)	$ -	$ (5,868,379)
3	Industrial Sector	$ 1,174,058	$ -	$ -	$ -	$ 1,174,058
4	Agricultural Sector	$ (294,942)	$ -	$ -	$ -	$ (294,942)
5	Public Sector	$ -	$ -	$ -	$ -	$ -
6	Cross Cutting Sector					
7	Emerging Tech	$ -	$ -	$ -	$ -	$ -
8	WE&T	$ -	$ 114,587	$ -	$ -	$ 114,587
9	Finance	$ -	$ -	$ -	$ -	$ -
10	Codes & Standards	$ -	$ -	$ -	$ -	$ -
11	Portfolio Support	$ 882,221	$ 49,549	$ 115,757	$ -	$ 1,047,528
12	OBF Loan Pool					$ -
13	**Portfolio Subtotal [2]**	**$ (5,654,388)**	**$ 164,136**	**$ (306,347)**	**$ -**	**$ (5,796,599)**

[2] excludes EM&V and Portfolio Oversight

Table 1.2a - MCAL Total Cost Recovery Request, Including REN/CCA and Other Costs (IOU Only)[4]

Line	Portfolio Administrator	(a) PA Programs	(b) ED Portfolio Oversight [5]	(c) EMV PA	(d) EMV ED	(e) Unspent & Uncommitted Funds for 2024-2027 Offset(2)	(f) Total
1	Southern California Edison	$ -	$ -	$ -	$ -	$ -	$ -
2	SoCal REN	$ -	$ -	$ -	$ -	$ -	$ -
3	3C-REN	$ -	$ -	$ -	$ -	$ -	$ -
4	I-REN	$ -	$ -	$ -	$ -	$ -	$ -
5	RREN Central[6]	$ -	$ -	$ -	$ -	$ -	$ -
6	RREN North[6]	$ -	$ -	$ -	$ -	$ -	$ -
7	Bay-REN (SW Program)	$ -	$ -	$ -	$ -	$ -	$ -
8	Ava Community Energy	$ -	$ -	$ -	$ -	$ -	$ -
9	CleanPowerSF	$ -	$ -	$ -	$ -	$ -	$ -
10	Marin Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
11	Peninsula Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
12	Redwood Coast Energy Authority	$ -	$ -	$ -	$ -	$ -	$ -
13	SD REN	$ -	$ -	$ -	$ -	$ -	$ -
14	San Jose Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
15	Sonoma Clean Power	$ -	$ -	$ -	$ -	$ -	$ -
16	**Total**	$ -	$ -	$ -	$ -	$ -	$ -
17	**Collected 2024 Recovery**						$ -
18	**Expected 2025 Recovery**						$ -
19	**Remaining Cost Recovery**						$ -

[5] Funding reserved for EE technical consultants pursant to D.23-06-055 OP 9
[6] Rural REN was split into two RENs in D. 24-09-031 and budgets were adjusted to account for split and timing of when REN started

Table 1.2b - TUAL Total Cost Recovery Request, Including REN/CCA and Other Costs (IOU Only)

Line	Portfolio Administrator	(a) PA Programs	(b) ED Portfolio Oversight [5]	(c) EMV PA	(d) EMV ED	(e) Unspent & Uncommitted Funds for 2024-2027 Offset[3]	(f) Total
1	Southern California Edison	$ -	$ -	$ -	$ -	$ -	$ -
2	SoCal REN	$ -	$ -	$ -	$ -	$ -	$ -
3	3C-REN	$ -	$ -	$ -	$ -	$ -	$ -
4	I-REN	$ -	$ -	$ -	$ -	$ -	$ -
5	RREN Central[6]	$ -	$ -	$ -	$ -	$ -	$ -
6	RREN North[6]	$ -	$ -	$ -	$ -	$ -	
7	Bay-REN (SW Program)	$ -	$ -	$ -	$ -	$ -	$ -
8	Ava Community Energy	$ -	$ -	$ -	$ -	$ -	$ -
9	CleanPowerSF	$ -	$ -	$ -	$ -	$ -	$ -
10	Marin Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
11	Peninsula Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
12	Redwood Coast Energy Authority	$ -	$ -	$ -	$ -	$ -	$ -
13	SD REN	$ -	$ -	$ -	$ -	$ -	$ -
14	San Jose Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
15	Sonoma Clean Power	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total**	$ -	$ -	$ -	$ -	$ -	$ -

[5] Funding reserved for EE technical consultants pursant to D.23-06-055 OP 9
[6] Rural REN was split into two RENs in D. 24-09-031 and budgets were adjusted to account for split and timing of when REN started

Table 1.2c - Change Total Cost Recovery Request, Including REN/CCA and Other Costs (IOU Only)

Line	Portfolio Administrator	(a) PA Programs	(b) ED Portfolio Oversight [5]	(c) EMV PA	(d) EMV ED	(e) Unspent & Uncommitted Funds for 2024-2027 Offset[3]	(f) Total
1	Southern California Edison	$ -	$ -	$ -	$ -	$ -	$ -
2	SoCal REN	$ -	$ -	$ -	$ -	$ -	$ -
3	3C-REN	$ -	$ -	$ -	$ -	$ -	$ -
4	I-REN	$ -	$ -	$ -	$ -	$ -	$ -
4	RREN Central[6]	$ -	$ -	$ -	$ -	$ -	$ -
4	RREN North[6]	$ -	$ -	$ -	$ -	$ -	$ -
4	Bay-REN (SW Program)	$ -	$ -	$ -	$ -	$ -	$ -
8	Ava Community Energy	$ -	$ -	$ -	$ -	$ -	$ -
9	CleanPowerSF	$ -	$ -	$ -	$ -	$ -	$ -
10	Marin Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
11	Peninsula Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
12	Redwood Coast Energy Authority	$ -	$ -	$ -	$ -	$ -	$ -
13	SD REN	$ -	$ -	$ -	$ -	$ -	$ -
14	San Jose Clean Energy	$ -	$ -	$ -	$ -	$ -	$ -
15	Sonoma Clean Power	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total**	$ -	$ -	$ -	$ -	$ -	$ -

[5] Funding reserved for EE technical consultants pursant to D.23-06-055 OP 9
[6] Rural REN was split into two RENs in D. 24-09-031 and budgets were adjusted to account for split and timing of when REN started

Table 1.3 Portfolio Cost Recovery Request by Fuel (IOU Only)

Line	Spending Budget & Cost Recovery Request	2023 Unspent Funds	2024	2025	2026	2027	2024-2027
1	IOU (excluding fuel substitution budget)		$ -	$ -	$ -	$ -	$ -
2	IOU Budget forecasted to support fuel sub		$ -	$ -	$ -	$ -	$ -
3	**Total cost recovery request for IOU portfolio (excluding offset)**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
4	**IOU Pre-2024 Estimated Unspent & Uncommitted Funds to Offset 2024-2027 Cost Recovery**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Cost Recovery Request for IOU Portfolio (including offset)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
6	Applicable electric split						
7	Applicable gas split	100%	100%	100%	100%	100%	
8	Electric portion for cost recovery (excluding fuel sub budget)	$ -	$ -	$ -	$ -	$ -	$ -
9	Fuel sub applicable electric split	100%	100%	100%	100%	100%	
10	Electric portion for cost recover (fuel sub budget)	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total electric portion for cost recovery for IOU portfolio**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12	**Total Gas portion for cost recovery for IOU portfolio**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
13	Electric split (with fuel sub)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
14	Gas split (with fuel sub)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

Table 1.4 Prior Years Unspt Funds as of August 2024 (All PA)

Line		PY 2017	PY 2018	PY 2019	PY 2020	PY 2021	PY 2022	PY 2023	PY 2024	TOTAL 2017-2024
1	**Unspent & Uncommitted**	$ -	$ -	$ -	$ -	$ (74,272)	$ (323,172)	$ (5,321,854)	$ (7,644,320)	**$ (13,363,618)**
2	EM&V			$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (74,272)**	**$ (323,172)**	**$ (5,321,854)**	**$ (7,644,320)**	**$ (13,363,618)**
4	**Unspent & Uncommitted Pre-2023 EM&V, and IOU Program Funds for 2024-2027 Rate Offset**									
5	EM&V - PA Funds									$ -
6	EM&V - CPUC Funds									$ -
7	IOU Program Funds									$ -
8	**Total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Table 1.5 - 4 Year Funding Sources - RENs/CCAs (RENs/CCAs Only)

Line		**PG&E[1]**		**SDG&E**		**SCE**	**SCG**
1	**Year**	**Electric $**	**Gas $**	**Gas $**	**Electric $**	**Electric $**	**Gas $**
2	2024	$ 11,592,881	$ 8,056,070				
3	2025	$ 11,707,788	$ 7,485,307				
4	2026	$ 12,533,912	$ 7,682,075				
5	2027	$ 11,725,273	$ 8,490,715				
6	**Total**	**$ 47,559,854**	**$ 31,714,167**	$ -	$ -	$ -	$ -

[1] MCE Spending Budget Request for 2024-2027 Excluding Offset

Table 1.6 - Mid-Cycle Advice Letter Funding Breakdown (ALL PAs)

Line	Year	2024 Reported Expenditures	2024 Carryover Funding[7]	2025 TUAL	2026 MCAL	2027 MCAL	Unspent/Uncommited Funds for Offset[8] [9]	2024-2027 Funding Total
1	2024	$ 8,343,217					$ (12,469,059)	**$ (4,125,842)**
2	2025			$ 19,193,096			$ -	**$ 19,193,096**
3	2026		$ 3,661,414		$ 20,215,987		$ (20,098,673)	**$ 117,314**
4	2027					$ 20,215,987		**$ 20,215,987**

[7] Funding committed in 2024 but not yet spent will be carried forward into future years of the funding cycle or funding that is being intentionally moved to future years.
2024 carryover funding is already included in the MCAL budgets and is not added to the totals.
[8] The 2024 Unspent/Uncommited amount matches MCE's TUAL amount of $12,469,059.
[9] The 2026 Unspent/Uncommited amount consists of 5,719,298 in pre-2024 funds, $7,644,320 in unspent 2024 funds, and $6,735,056 in estimated unspent 2025 funds.

Table 2.1a - MCAL Updated Annual and Cumulative Total System Benefit Forecast

Line	Segment	PY 2024-Actual	PY 2025 TUAL	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 2,488,664	$ 22,662,424	$ 19,569,409	$ 21,490,567	**$ 66,211,064**
2	Market Support	$ -	$ -	$ -	$ -	**$ -**
3	Equity	$ 793,573	$ 1,093,988	$ 2,119,714	$ 2,235,414	**$ 6,242,689**
4	**Total TSB Forecast**	**$ 3,282,237**	**$ 23,756,413**	**$ 21,689,123**	**$ 23,725,981**	**$ 72,453,754**
5	CPUC TSB Goal	$ 23,601,101	$ 23,753,413	$ 21,689,123	$ 23,725,981	$ 92,769,618
6	*TSB Forecast / TSB Goal [1]*	*14%*	*100%*	*100%*	*100%*	*78%*

[1] D.21-09-037 at 24: Non-IOU program administrators may propose to revise their goals and savings forecasts in the true-up or mid-cycle advice letter.

Table 2.1b - TUAL Annual and Cumulative Total System Benefit Forecast

Line	Segment	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 22,566,920	$ 22,662,424	$ 22,770,876	$ 22,834,597	**$ 90,834,817**
2	Market Support	$ -	$ -	$ -	$ -	**$ -**
3	Equity	$ 1,034,181	$ 1,093,988	$ 1,157,605	$ 1,224,826	**$ 4,510,600**
4	**Total TSB Forecast**	**$ 23,601,101**	**$ 23,756,413**	**$ 23,928,480**	**$ 24,059,424**	**$ 95,345,418**
5	CPUC TSB Goal	$ 23,601,101	$ 23,753,413	$ 23,928,480	$ 24,059,424	$ 95,342,418
6	*TSB Forecast / TSB Goal [2]*	*100%*	*100%*	*100%*	*100%*	*100%*

[2] D.21-09-037 at 23: The goals from the potential and goals studies apply to IOU program administrators and not to non-IOU prorgram administrators.

Table 2.1c - Change Annual and Cumulative Total System Benefit Forecast

Line	Segment	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ (20,078,256)	$ -	$ (3,201,467)	$ (1,344,030)	**$ (24,623,753)**
2	Market Support	$ -	$ -	$ -	$ -	**$ -**
3	Equity	$ (240,608)	$ -	$ 962,109	$ 1,010,588	**$ 1,732,089**
4	**Total TSB Forecast**	**$ (20,318,864)**	**$ -**	**$ (2,239,357)**	**$ (333,443)**	**$ (22,891,664)**
5	CPUC TSB Goal	$ -	$ -	$ (2,239,357)	$ (333,443)	$ (2,572,800)
6	*TSB Forecast / TSB Goal [3]*	*-86%*	*0%*	*0%*	*0%*	*-22%*

[3] Difference in % of goals achieved from the TUAL to the MCAL

Table 2.2a - MCAL Updated Annual and Cumulative Codes and Standards Savings Forecast

Line	Savings Unit	PY 2024-Actual	PY 2025 TUAL	PY 2026	PY 2027	Cumulative
1	GWh CPUC [1]	**N/A**	**N/A**	**N/A**	**N/A**	**-**
2	GWh CPUC Target [1]	N/A	N/A	N/A	N/A	-
3	*GWh Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
4	MW Forecast	**N/A**	**N/A**	**N/A**	**N/A**	**-**
5	MW CPUC Target [1]	N/A	N/A	N/A	N/A	-
6	*MW Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
7	MMThm Forecast	**N/A**	**N/A**	**N/A**	**N/A**	**-**
8	MMThm CPUC Target [1]	N/A	N/A	N/A	N/A	-
9	*MMThm Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*

[1] TSB Goal set in decions D.XX-XX-XXX (update with latest P&G decision)

Table 2.2b - TUAL Annual and Cumulative Codes and Standards Savings Forecast

Line	Savings Unit	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	GWh CPUC [2]	**N/A**	**N/A**	**N/A**	**N/A**	**-**
2	GWh CPUC Target [2]	N/A	N/A	N/A	N/A	-
3	*GWh Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
4	MW Forecast	**N/A**	**N/A**	**N/A**	**N/A**	**-**
5	MW CPUC Target [2]	N/A	N/A	N/A	N/A	-
6	*MW Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
7	MMThm Forecast	**N/A**	**N/A**	**N/A**	**N/A**	**-**
8	MMThm CPUC Target [2]	N/A	N/A	N/A	N/A	-
9	*MMThm Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*

[2] TSB Goal set in decions D.21-09-037 and corrected in D.22-05-016

Table 2.2c - Change Annual and Cumulative Codes and Standards Savings Forecast

Line	Savings Unit	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	GWh CPUC [3]	N/A	N/A	N/A	N/A	-
2	GWh CPUC Target [3]	N/A	N/A	N/A	N/A	-
3	*GWh Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
4	MW Forecast	N/A	N/A	N/A	N/A	-
5	MW CPUC Target [3]	N/A	N/A	N/A	N/A	-
6	*MW Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
7	MMThm Forecast	N/A	N/A	N/A	N/A	-
8	MMThm CPUC Target [3]	N/A	N/A	N/A	N/A	-
9	*MMThm Forecast/Target*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*

[3] Difference in % of goals achieved from the TUAL to the MCAL

Table 2.3a - MCAL Updated Annual and Cumulative Budget

Line	Segment	PY 2024-Actual	PY 2025 TUAL	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 5,329,717	$ 12,667,443	$ 13,475,653	$ 13,475,653	$ 44,948,465
2	Market Support	$ 965,264	$ 982,711	$ 1,081,086	$ 1,081,086	$ 4,110,146
3	Equity	$ 4,272,503	$ 4,775,218	$ 4,850,610	$ 4,850,610	$ 18,748,941
4	Codes and Standards	$ -	$ -	$ -	$ -	$ -
5	EM&V (PA and ED)	$ 204,138	$ 767,724	$ 808,639	$ 808,639	$ 2,589,141
6	**Total Budget w/o OBF Loan Pool**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
7	Market Support and Equity, percent of the Total Portfolio Budget **w/o OBF Loan Pool**					29%
8	OBF Loan Pool Addition	$ -	$ -	$ -	$ -	$ -
9	**Budget excluding Portfolio Oversight**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
10	ED Portfolio Oversight	$ -	$ -	$ -	$ -	$ -
11	**Total Portfolio Budget w/ ED Portfolio Oversight**	**$ 10,771,623**	**$ 19,193,096**	**$ 20,215,987**	**$ 20,215,987**	**$ 70,396,693**
12	**Approved Budget Cap [4]**					**$ 78,217,316**

[4] Decision 23-06-055 OP5

Table 2.3b - TUAL Annual and Cumulative Budget

Line	Segment	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ 12,968,308	$ 12,667,443	$ 12,544,743	$ 12,422,359	$ 50,602,854
2	Market Support	$ 975,340	$ 982,711	$ 990,102	$ 997,858	$ 3,946,010
3	Equity	$ 4,919,346	$ 4,775,218	$ 4,712,055	$ 4,648,669	$ 19,055,287
4	Codes and Standards	$ -	$ -	$ -	$ -	$ -
5	EM&V (PA and ED)	$ 785,958	$ 767,724	$ 760,287	$ 752,870	$ 3,066,840
6	**Total Budget w/o OBF Loan Pool**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**
7	Market Support and Equity, percent of the Total Portfolio Budget **w/o OBF Loan Pool**					30%
8	OBF Loan Pool Addition	$ -	$ -	$ -	$ -	$ -
9	**Budget excluding Portfolio Oversight**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**
10	ED Portfolio Oversight	$ -	$ -	$ -	$ -	$ -
11	**Total Portfolio Budget w/ ED Portfolio Oversight**	**$ 19,648,951**	**$ 19,193,096**	**$ 19,007,187**	**$ 18,821,757**	**$ 76,670,990**

Table 2.3c - Change Annual and Cumulative Budget

Line	Segment	PY 2024	PY 2025	PY 2026	PY 2027	Cumulative
1	Resource Acquisition	$ (7,638,591)	$ -	$ 930,909	$ 1,053,293	$ (5,654,388)
2	Market Support	$ (10,076)	$ -	$ 90,984	$ 83,228	$ 164,136
3	Equity	$ (646,842)	$ -	$ 138,555	$ 201,940	$ (306,347)
4	Codes and Standards	$ -	$ -	$ -	$ -	$ -
5	EM&V (PA and ED)	$ (581,820)	$ -	$ 48,352	$ 55,769	$ (477,698)
6	**Total Budget w/o OBF Loan Pool**	**$ (8,877,328)**	**$ -**	**$ 1,208,800**	**$ 1,394,231**	**$ (6,274,297)**
7	Market Support and Equity, percent of Total Budget **w/o OBF Loan Pool**					2%
8	OBF Loan Pool Addition	$ -	$ -	$ -	$ -	$ -
9	**Budget excluding Portfolio Oversight**	**$ (8,877,328)**	**$ -**	**$ 1,208,800**	**$ 1,394,231**	**$ (6,274,297)**
10	ED Portfolio Oversight	$ -	$ -	$ -	$ -	$ -
11	**Total Portfolio Budget w/ ED Portfolio Oversight**	**$ (8,877,328)**	**$ -**	**$ 1,208,800**	**$ 1,394,231**	**$ (6,274,297)**

Table 3a - MCAL Updated Portfolio Cost Effectiveness Ratios (PY 2024-2027)[1]

Line			TRC ratio	PAC ratio	RIM ratio
1	Segment	**Resource Acquisition**	**1.01**	1.48	0.35
2		Market Support	0.00	0.00	0.00
3		Equity	0.37	0.39	0.30
4		Codes and Standards (C&S)	N/A	N/A	N/A
5	Portfolio	*Including* C&S	N/A	N/A	N/A
6		*Excluding* C&S	0.80	1.04	0.34

[1] 2024 Actuals and the 2025 TUAL forecast are used in the updated forecast

Table 3b - TUAL Portfolio Cost Effectiveness Ratios (PY 2024-2027)

Line			TRC ratio	PAC ratio	RIM ratio
1	Segment	**Resource Acquisition**	**1.03**	1.79	1.08
2		Market Support	0.00	0.00	0.00
3		Equity	0.26	0.26	0.27
4		Codes and Standards (C&S)	N/A	N/A	N/A
5	Portfolio	*Including* C&S	N/A	N/A	N/A
6		*Excluding* C&S	0.84	1.25	0.88

Table 3c - Change Portfolio Cost Effectiveness Ratios (PY 2024-2027)

Line			TRC ratio	PAC ratio	RIM ratio
1	Segment	**Resource Acquisition**	-0.02	-0.31	-0.73
2		Market Support	0.00	0.00	0.00
3		Equity	0.11	0.12	0.03
4		Codes and Standards (C&S)	N/A	N/A	N/A
5	Portfolio	*Including* C&S	N/A	N/A	N/A
6		*Excluding* C&S	-0.04	-0.21	-0.54

Table 3d - Societal Cost Test for 2026-2027

Line			2026		2027		2 Yr Total	
1			**Base**	**High**	**Base**	**High**	**Base**	**High**
2	Segment	**Resource Acquisition**	**1.45**	**1.50**	**1.56**	**1.60**	**1.41**	**1.46**
3		Market Support	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
4		Equity	**0.75**	**0.75**	**0.78**	**0.78**	**0.78**	**0.78**
5		Codes and Standards (C&S)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
6	Portfolio	*Including* C&S	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
7		*Excluding* C&S	**1.19**	**1.23**	**1.28**	**1.31**	**1.18**	**1.21**

Table 4 - Portfolio Statewide and Third-party Contribution Percentage Requirements (IOU only)

Line	Budget Component	Third Party Budget	Cumulative Total Budget w/o OBF Loan Pool	Contribution Percentage	Minimum Threshold
1	Statewide [1]	$ 285,586,875	$ 76,670,990	372%	20%
2	Third-party [2]	$ 754,298,117	$ 76,670,990	984%	60%

[1] SW program definition per D.16-08-019, OP 24, OP 38, & OP 39.

[2] Third party program definition per D.16-08-019, OP 10, includes SW third-party budgets

[1] Updated Forecasts for 2024-2027 include 2024 Actuals, 2025 TUAL Forecast, and Updated forecasts for 2026 and 2027.

Please ensure that on Table A1, each IOU lists all of the SW program and the asosciated IOU specific budget.

Appendix 1 - 2024 - 2027 Program Portfolio Budget and Targets

						Updated MCAL Forecasts [1]					TUAL Filing					Change					
(a) Program ID	(b) Program Name	(c) Target Exempt	(d) Program Type	(e) Business Sector	(f) Portfolio Segment	(l) Budget	(m) TSB	(n) GWh	(o) MW	(p) MMThm	(g) Budget	(h) TSB	(i) GWh	(j) MW	(k) MMThm	(q) Budget	(r) TSB	(s) GWh	(t) MW	(u) MMThm	(v) Change Notes
MCE01	MF Energy Savings (MFES)	No	Core PA	Residential	Equity	$ 3,023,426	$ 1,096,346	(0.30)	0.01	0.06	$ 3,101,185	$ 1,454,954	(0.17)	0.01	0.09	$ (77,760)	$ (358,608)	(0.13)	$ 0	$ (0)	
MCE01c	MF Strategic Energy Management	No	Core PA	Residential	Resource	$ 1,331,472	$ 1,354,426	1.14	0.06	0.06	$ 1,712,387	$ 2,638,593	2.40	-	0.08	$ (380,915)	$ (1,284,166)	(1.26)	$ 0	$ (0)	
MCE01d	Residential Efficiency Market	No	Core PA	Residential	Resource	$ 3,177,469	$ 4,367,739	0.14	0.16	0.15	$ 5,665,098	$ 7,791,224	(0.79)	(0.16)	0.40	$ (2,487,629)	$ (3,423,485)	0.93	$ 0	$ (0)	Slow uptake in market
MCE02a	Com Deemed	No	Core PA	Commercial	Resource	$ 1,491,264	$ 2,118,129	0.58	0.08	0.16	$ 1,679,729	$ 2,002,994	1.22	0.24	0.14	$ (188,465)	$ 115,135	(0.64)	$ (0)	$ 0	
MCE02b	Com Custom	No	Core PA	Commercial	Resource	$ 1,871,430	$ 2,432,690	2.49	0.18	0.03	$ 4,363,533	$ 6,800,409	7.47	0.45	0.09	$ (2,492,102)	$ (4,367,719)	(4.98)	$ (0)	$ (0)	Implementer now enrolled in Com Efficiency Market program
MCE02c	Com Strategic Energy Management	No	Core PA	Commercial	Resource	$ 2,028,364	$ 2,181,143	2.85	0.08	0.14	$ 2,706,256	$ 4,632,460	7.13	-	0.29	$ (677,892)	$ (2,451,316)	(4.27)	$ 0	$ (0)	
MCE08	SF Home Energy Savings	No	Core PA	Residential	Equity	$ 12,013,269	$ 4,485,760	(0.15)	0.44	0.15	$ 11,831,909	$ 3,055,646	(0.11)	0.40	0.13	$ 181,359	$ 1,430,114	(0.04)	$ 0	$ 0	
MCE02d	Com Efficiency Market	No	Core PA	Commercial	Resource	$ 22,361,422	$ 39,981,023	61.26	8.13	0.02	$ 24,345,637	$ 59,321,351	94.73	11.32	(0.17)	$ (1,984,215)	$ (19,340,328)	(33.47)	$ (3)	$ 0	
MCE02e	Small Business Energy Advantage	No	Core PA	Commercial	Equity	$ 3,135,083	$ 660,583	(0.47)	-	0.05	$ 3,660,786	$ -	-	-	-	$ (525,704)	$ 660,583	(0.47)	$ -	$ 0	Program Launched in mid-2024
MCE07	SF HER	No	Core PA	Residential	Resource	$ -	$ -	-	-	-	$ -	$ -	-	-	-	$ -	$ -	-	$ -	$ -	
MCE10a	Ind Deemed	No	Core PA	Industrial	Resource	$ 503,889	$ 604,787	0.20	0.03	0.03	$ 371,734	$ 314,364	0.38	0.08	0.01	$ 132,154	$ 290,423	(0.18)	$ (0)	$ 0	
MCE10b	Ind Custom	No	Core PA	Industrial	Resource	$ 1,304,853	$ 3,419,311	0.55	0.04	0.11	$ 1,383,138	$ 2,924,179	1.00	0.03	0.13	$ (78,285)	$ 495,132	(0.45)	$ 0	$ (0)	
MCE10c	Ind SEM	No	Core PA	Industrial	Resource	$ 2,496,719	$ 4,422,503	2.17	0.02	0.41	$ 1,376,531	$ 2,139,981	2.38	-	0.18	$ 1,120,188	$ 2,282,522	(0.21)	$ 0	$ 0	MCE expects significant industrial savings in 2026
MCE11a	Ag Deemed	No	Core PA	Agricultural	Resource	$ 427,209	$ 200,074	0.19	0.00	0.00	$ 311,304	$ 133,813	0.35	-	0.00	$ 115,905	$ 66,261	(0.16)	$ 0	$ 0	
MCE11b	Ag Custom	No	Core PA	Agricultural	Resource	$ 477,381	$ 484,666	0.16	0.02	0.01	$ 316,309	$ 348,977	0.22	0.04	0.01	$ 161,071	$ 135,689	(0.07)	$ (0)	$ 0	
MCE11c	Ag SEM	No	Core PA	Agricultural	Resource	$ 573,879	$ 469,365	0.59	-	0.03	$ 1,145,798	$ 1,786,474	2.20	-	0.12	$ (571,918)	$ (1,317,109)	(1.61)	$ -	$ (0)	low AG SEM uptake
MCE16	Green Workforce Pathways	Yes	Core PA	WE&T	Market Support	$ 3,965,003	$ -	-	-	-	$ 3,850,416	$ -	-	-	-	$ 114,587	$ -	-	$ -	$ -	
MCE97	CPUC EM&V	No	Core PA	Cross-Cutting	EM&V	$ 1,431,002	$ -	-	-	-	$ 1,840,104	$ -	-	-	-	$ (409,102)	$ -	-	$ -	$ -	
MCE98	MCE EM&V	No	Core PA	Cross-Cutting	EM&V	$ 1,158,140	$ -	-	-	-	$ 1,226,736	$ -	-	-	-	$ (68,596)	$ -	-	$ -	$ -	
MCE100	IDSM Pilot	No	Core PA	Residential	Resource	$ 3,000,000	$ 3,200,000	-	-	-	$ 4,000,000	$ -	-	-	-	$ (1,000,000)	$ 3,200,000	-	$ -	$ -	New program
MCE101-Equity-PS	Equity Portfolio Support	No	Core PA	Portfolio Support	Equity	$ 577,163	$ -	-	-	-	$ 461,406	$ -	-	-	-	$ 115,757	$ -	-	$ -	$ -	
MCE101-MS-PS	Market Support Portfolio Support	No	Core PA	Portfolio Support	Market Support	$ 145,143	$ -	-	-	-	$ 95,594	$ -	-	-	-	$ 49,549	$ -	-	$ -	$ -	
MCE101-RA-PS	Resource Acquisition Portfolio Support	No	Core PA	Portfolio Support	Resource	$ 2,107,621	$ -	-	-	-	$ 1,225,400	$ -	-	-	-	$ 882,221	$ -	-	$ -	$ -	
MCE01-R	MF Energy Savings (MFES) Resource	No	Core PA	Residential	Resource	$ 1,795,494	$ 975,208	(0.53)	-	0.06	$ -	$ -	-	-	-	$ 1,795,494	$ 975,208	(0.53)	$ -	$ 0	New program
Total						**$ 70,396,693**	**72,453,754**	**70.89**	**9.24**	**1.48**	**$ 76,670,990**	**95,345,418**	**118.42**	**12.42**	**1.498**	**$ (6,274,297)**	**(22,891,664)**	**(47.53)**	**(3)**	**(0)**	

Appendix 2 - Energy Efficiency Cap And Target Expenditure Projections (Cumulative for PY 2024-2027)
Program level budgets can be found on tab A1 - Program Table

		Expenditures			Performance		
Line	**Budget Category**	**(a) Non-Third Party Qualifying Costs**	**(b) Third Party Qualifying Costs**	**(c) Total Portfolio**	**(d) Percent of Budget [6]**	**(e) Cap Percentage**	**(f) Target %**
1	**Administrative Costs**						
2	PA [1]	$ 3,030,271		$ 3,030,271	4.5%	10.0%	
3	Non-PA Third Party & Partnership [2]	$ 1,471,513	$ -	$ 1,471,513	2.2%		10.0%
4	PA & Non-PA Target Exempt Programs [3]	$ 160,276	$ -	$ 160,276			
5	**Marketing and Outreach Costs**						
6	Marketing & Outreach	$ 1,645,999	$ -	$ 1,645,999	2.4%		6.0%
7	**Direct Implementation Costs**						
8	Incentives and Rebates	$ 31,562,653	$ -	$ 31,562,653			
9	Non Incentives and Non Rebates	$ 23,132,113	$ -	$ 23,132,113	34.3%		20.0%
10	Target Exempt (Non Incentives and Non Rebates)	$ 3,804,728	$ -	$ 3,804,728			
11	**EM&V Costs (PA and ED) [4]**	$ 2,589,141	$ -	$ 2,589,141	3.8%	4.0%	
11a	EM&V - PA	*$ 1,158,140*		*$ 1,158,140*			
11b	EM&V - ED	*$ 1,431,002*		*$ 1,431,002*			
12	**PA Spending Budget Request** (excluding OBF Loan Pool Additions and excluding ED Portfolio Oversight)	**$ 67,396,693**	**$ -**	**$ 67,396,693**			
13	**Total Third-Party Qualifying Costs [5]**				0.0%		60.0%
14	**OBF Loan Pool Addition**	$ -		$ -			
15	**PA Spending Budget Request** (excluding ED Portfolio Oversight) [8]			**$ 67,396,693**			
16	**ED Portfolio Oversight [10]**	$ -		$ -			
17	**EE-Funded IDSM**	$ 3,000,000		$ 3,000,000		2.5%	
	Multi-DER IDSM[7]	$ -					
18	**PA Spending Budget Request**			**$ 70,396,693**			

[1] 10% cap requirement based on D. 09-09-047 for IOU only

[2] New Third party program definition per D.16-08-019, OP 10. For Row 3 of this table, the "Third Party & Partnership" administrative costs under the "Non-Third Party Qualifying Costs" column are costs for programs that met the old Third Party definition prior to the transition to the new third party definition.

[3] Target Exempt Programs include: Emerging Technologies, Workforce Education & Training, Strategic Energy Resources (SER) program, 3P Placeholder for Public LGPs, and Codes & Standards programs (excluding Building Codes Advocacy, Appliance Standards Advocacy and National Standards Advocacy).

[4] For IOUs, EM&V costs only includes IOU's Total EM&V budget (PA + ED) and does not include REN or CCAs EM&V budget. For RENs & CCAs, include EM&V-PA Budget and EM&V-ED = $0 . The EM&V percentage is based on PA's total portfolio budget (from line 13) RENs, and CCAs

[5] IOU's Third-Party Implementer Contracts (as defined per D.16-08-019, OP 10) includes third-party contract and incentive budgets and statewide qualifying contract and incentive budgets. Calculation of (d) Percent of Budget for Third-Party Implementer Contracts uses $1,179,559,488 as its denominator.

[6] With the exception of Third Party Implementer Contracts as noted in footnote [5], calculation of (d) Percent of Budget uses $1,143,059,488 as the denominator; equal to line 15 PA Budget Spending Request.

[7] D.23-06-055 OP 29: Portfolio administrators (PAs) may set aside up to 2.5 percent, or $4 million, whichever is greater, up to a maximum of $15 million, from within their total budgets during 2024-2027 approved in this decision to fund innovative integrated demand-side management projects, including ongoing load-shifting that is not event-based. Energy efficiency funding shall not be used for rebating capital costs of non-efficiency technologies, except as already provided for electric panel upgrades in Decisions 19-08-009 and 23-04-035.

[8] $33,815,039 Pensions & Benefits Budget was excluded; not funded by the EE Portfolio

[9] Includes actual expenditures for 2024, 2025 TUAL forecasts, and updated values for 2026-2027 forecasts.

[10] Funding reserved for EE technical consultant pursant to D.23-06-055 OP 9

[11] D.23-06-055, COL 1, COL 4, and table 1 (p.6), which set the SW funding allocations for IOUs and 10% for SoCalGas only.

[12] D.18-05-041 OP10: Each IOU PA should set aside a minimum annual amount of $1 million for the residential sector and a load-share-proportional amount of $20 million for the commercial sector from each IOU PA's IDSM budget to test and deploy integration strategies, which may test multiple program design and customer incentive approaches, as well as multiple technology types, with emphasis on demand-response-capable control technologies.

Appendix 3 - RTR Implementation Descriptions per D.23-06-055

ED staff request that PAs describe their progress on recommendations from PY2022 onwards evaluations that impact programs in the current budget cycle.

	Study	Best Practice / Recommendations (Verbatim from Final Report)	Recommendation Recipient	(PA Response)	PA Response Notes	Proposed RTR Implementation				
CALMAC ID	Study Name	Recommendations	If incorrect, please indicate and redirect in notes.	Choose: Accepted, Rejected, or Other	Examples: Describe specific program change, give reason for rejection, or indicate that it's under further review.	Next Steps: For each accepted recommendation, outline the steps required for implementation, responsible parties, and deadlines. For each rejected recommendation, document the reason provided for rejection. Outline any potential follow-up actions or considerations for the future.	Timeline: Set deadlines for the completion of each action. Include a start date and end date when possible.	Status: Track the status of each action item (e.g., Not Started, In Progress, Completed).	Notes: Add notes for any additional information or updates.	Impacted Programs: Identify which programs (program IDs) would be impacted by the action items.
Overall conclusions and recommendations						**Proposed Next Steps**				
CPU0372.01	PY 2022 Regional Energy Networks Impact	DNV recommends that the PAs (utilities, RENs, and CCAs) and/or their representatives (e.g., technical and regulatory consultants) continue or begin to attend all official coordination meetings as defined in the JCMs even when third-party implementers manage the programs. The PAs should attend the coordination meetings and then direct the program implementers to follow through with any necessary actions identified during the meetings. The PAs should consider including a RACI (responsible, accountable, consulted, informed) chart in the JCMs and PIPs that defines the role of PAs, implementers, and any other stakeholders. A RACI chart would help clarify who needs to attend the coordination meetings, define their role, and help eliminate any confusion related to coordination efforts. The RACI chart should be a living document and an updated version of the RACI could be included with both the JCM and PIP documentation. DNV also recommends that attendance at the meetings be documented and made available to future evaluators.	All RENs, MCE	Accepted	MCE's program staff and/or technical and regulatory consultants currently attend coordination meetings, as described in the Joint Cooperation Memos. MCE has Joint Cooperation Memos with PG&E and BayREN, which outline how program managers and consultants meet on a regular basis to review program changes, prevent double-dipping, and check on data sharing needs. Attendance is taken at these meetings, and can be made available to evaluators upon request. MCE's JCMs and PIPs don't currently have RACI charts dedicated to roles for coordination meetings, but these could be developed, if deemed helpful. The JCMs and PIPs currently specify the roles and responsibilities of PAs, implementers, and other stakeholders.	MCE will review the feasibility of developing RACI charts for both the Joint Cooperation Memos (JCMs) and Program Implementation Plans (PIPs) to further clarify stakeholder roles and responsibilities. If implemented, MCE will coordinate with BayREN and PG&E to align the format and definitions used in the RACI charts. MCE will also explore including these RACI charts as appendices in future JCM and PIP updates to ensure they remain living documents.	Q2 2026 – Evaluate feasibility and develop draft RACI chart framework. Q3 2026 – Coordinate with BayREN and PG&E on alignment and finalize format. Q4 2026 – Include RACI charts in updated JCMs and PIPs.	Planned	MCE's JCMs and PIPs already define key coordination roles and responsibilities. The addition of RACI charts would further enhance clarity but will depend on inter-PA agreement for consistency across documentation.	All energy efficiency programs managed under the Joint Cooperation Memos (including Residential, Commercial, Industrial, Agricultural, and Cross-Cutting).

CALMAC ID	Study Name	PA	Recommendation
CPU0367.01	PY 2018 - 2021 Forward-looking Smart Thermostat Study	SCE	There are program opportunities to increase smart thermostat penetration in households with air-conditioning in hot climate zones. Programs should aim to expand the penetration of smart thermostats that can operate as part of a "fleet" serve as virtual power plants (VPPs) to provide direct relief to the overloaded parts of the grid
CPU0380.01	PY 2022 Midstream Commercial Water-Heating Impact	SCG	To increase the effectiveness and adoption of the online coupon tool, the Program implementer should enhance awareness and promotion of the tool among contractors. This could include targeted communication campaigns, training sessions on how to use the tool, and demonstrating the benefits and ease of purchasing equipment from big box stores using the coupons.
		SCG	The Program implementer should target outreach efforts and support to distributors and contractors in other parts of the state beyond southern California. This could include tailored marketing campaigns, incentives, and training programs to increase awareness and participation statewide.
		SCG	The Program administrator and implementer should formalize a process of verifying the eligibility of multifamily installations to ensure equipment is only installed on nonresidential/commercial rate meters.
CPU0369.01	PY 2022 Local 3-Party Programs Impact	All IOUs	Other programs should consider emulating the strategies these programs have taken to achieve success, including offering measures that better align with customer preferences, such as electrification and deeper gas usage saving measures, and employing more effective outreach strategies, such as direct multi-language outreach and community engagement (e.g., events).
		All IOUs	Track efforts to obtain input from HTR/DAC communities and track HTR/DAC community input. It is essential to track when outreach includes two-way communication that allows communities to provide feedback.
		All IOUs	Existing and developing local 3PPs should take note of the marketing and outreach innovations that have continued to work for this pool of programs year-over-year: direct outreach and strategic partnerships.
		All IOUs	The next time PAs negotiate contracts with local 3PP implementers, they should include terms that cover a standardized equity framework.
CPU0372.01	PY 2022 Regional Energy Networks Impact	All RENs	RENs are in the unique position of being able to support more effectively CPUC policies and California's larger decarbonization goals through innovative solutions and scalable activities. For this reason, RENs should consider increasing efforts to create a pathway to electrification such as higher incentives and rebates, varying levels of incentives, and equityfocused multipliers that target low-income participants, DACs, and environmental justice areas
		All RENs	Given their mandate to pilot activities where there is no current utility or CCA program offering, specifically where there is potential for scalability to a broader geographic reach, we recommend that the RENs consider sharing their successes serving the multifamily sector (including best practices for addressing split incentives and renter equity) during their coordination meetings with utilities. This type of sharing could expand useful approaches beyond the RENs
		All RENs	We recommend that the RENs collaborate with the utilities and other stakeholders to share best practices and lessons learned from their experience and to identify opportunities for coordination and alignment of programs and incentives, particularly for programs that traditionally experience challenges serving the multifamily sector
		All RENs, MCE	DNV recommends that the PAs (utilities, RENs, and CCAs) and/or their representatives (e.g., technical and regulatory consultants) continue or begin to attend all official coordination meetings as defined in the JCMs even when third-party implementers manage the programs. The PAs should attend the coordination meetings and then direct the program implementers to follow through with any necessary actions identified during the meetings. The PAs should consider including a RACI (responsible, accountable, consulted, informed) chart in the JCMs and PIPs that defines the role of PAs, implementers, and any other stakeholders. A RACI chart would help clarify who needs to attend the coordination meetings, define their role, and help eliminate any confusion related to coordination efforts. The RACI chart should be a living document and an updated version of the RACI could be included with both the JCM and PIP documentation. DNV also recommends that attendance at the meetings be documented and made available to future evaluators.
		All RENs	The program should continue its successful effort to electrify and achieve realistic and ambitious single-family energy consumption reductions. However, the program should target more underserved populations that would not undertake similar upgrades without program support. To reach such customers, the program could increase incentives for populations unlikely to install expensive fuel substitution technologies without program support.
CPU0352.01	PY 2021 Local 3-Party Programs Impact (RZNET – SDGE4002)	SDG&E	Build more community input into all phases of program delivery.
		SDG&E	Local 3PPs are still in their nascent stages and more time is needed to determine the success of program delivery innovations in delivering deeper savings.
		SDG&E	PAs should include equity- and access-related metrics for all programs. Provide additional guidance relating to what practices and outcomes are consistent with ESJ Goals 4.1, 6.1, 8, and 9.
		SDG&E	Local 3PPs should work on consistently integrating equity and access in program design while continuing the current efforts. Strive to directly collaborate with community partners to improve outreach.
CPU0357.01	PY 2021 SoCalGas Residential EE Portfolio Impact	SCG	Recommendation 5a: A market study should be conducted to determine the share of tankless water heaters among recently installed water heaters for both the replacement and new construction market.
CPU0377.01	PY 2020-2022 Site-Level Normalized Metered Energy Consumption (NMEC) Impact and Net-to-Gross Evaluation	PG&E	Improve alignment between program implementers, PA staff, and evaluators on program evaluation and qualification requirements. Increasing clarity on data requirements among all parties and streamlining the process of data sharing across parties can reduce duplicative work and confusion. Follow-on work led by ED can facilitate this process.
		PG&E	To protect participants, the implementer should ensure that equipment is operational and meets the functional needs of the building and that the 12 months of pre-installation data is an actual representation of baseline energy usage with functional equipment. A simple functional check by the implementer on the existing equipment during the investigation phase could eliminate this risk without adding additional burden on the participants.

MCE will report on all community indicators that received unanimous approval from all Program Administrators. These indicators represent the final set of approved equity metrics to be included in the Annual Report Narrative and Spreadsheet.

MCE also recognizes that several additional indicators received mixed approval among Program Administrators. These potential indicators may be incorporated into future reporting cycles as methodologies are refined, data collection practices are standardized, and alignment across Program Administrators is achieved.

Agreed Upon Indicators

Indicator Type	Indicator	Purpose	Unit of Measurement	Methodology	Reporting Platform	Total Yes	Total No
Engagement Activities							
Participation	Description of types of engagement activities conducted relevant to equity segment, the number of activities conducted, and additional context for PAs to add about their engagement activities	Provide context to the overall annual engagement for the equity segment each year.	Summary Narrative	Description of engagement activities relevant to equity segment, including types of activities conducted, number of activities, audiences targeted, number of people reached, outreach methods, and any additional context,	Annual Report Narrative	12	0
Summary of Feedback							
Input	Number of people who provided feedback relevant to the equity segment	Track the number of people who provided equity segment feedback. These changes should also be tracked year to year to assess progress over time.	Count	Total number of people who provided feedback relevant to the equity segment during engagement activities.	Annual Report Spreadsheet	12	0
Input	Feedback themes from engagement activities relevant to the equity segment	Understand input from engagement activities related to the equity segment to then help make	List of key themes	List of key themes sentences from all equity segment engagement activities feedback in the Annual Report Key	Annual Report Narrative	12	0
Changes to Program							
Input	Changes to equity segment program design as needed, based on feedback	Ensure feedback for equity segment programs is informing equity segment programming.	Summary Narrative	Thematic summary of description of changes that were addressed and incorporated into equity segment	Annual Report Narrative	12	0

Additional Potential Indicators

Indicator Type	Indicator	Purpose	Unit of Measurement	Methodology	Reporting Platform	Total Yes	Total No
Engagement Activities							
Participation	Number of people in all engagement activities relevant to the equity segment	Track equity segment engagement. These changes should also be tracked year to year to assess	Count	Total number of people in all engagement activities relevant to the equity segment annually.	Annual Report Spreadsheet	7	5
Participation	People in partners' engagement activities relevant to the equity segment	Understand how effective partners are in engaging and building trust with equity segment populations.	Percent	Percentage determined by the number of participants in partners' engagement activities divided by the number of participants in all engagement activities. Partners would	Annual Report Spreadsheet	6	6
Input	Funding for partners' engagement activities related to the equity segment	Assess how funding correlates with how effective partners are in engaging and building trust with	Dollars	Amount of money spent to fund partners' engagement activities related to equity segment. Funding includes	Annual Report Spreadsheet	6	6
Awareness	People reached through online, telephone, or other outreach for the equity segment	Assess awareness of equity programs from equity segment population.	Percent	Percentage of emails opened from email campaign, rate of social media clicks, likes and shares, or percentage of	Annual Report Spreadsheet	6	6
Awareness	Equity segment inquiries	Assess awareness of equity programs from equity segment population.	Count	Total number of unique submissions of interest forms on websites, number of calls, number of emails, or forms for more information across all equity segment programs.	Annual Report Spreadsheet	7	5
Summary of Feedback							
Satisfaction	Equity segment participant satisfaction survey responses	Provides the count of surveys.	Count	Total number of completed surveys.	Annual Report Spreadsheet	6	6
Satisfaction	Rating from equity segment participant satisfaction surveys	Understand participant satisfaction with equity segment programs.	Numerical Rating	Average post-participation satisfaction rating for equity segment and/or programs using standard rating system of	Annual Report Spreadsheet	6	6

	Study	Best Practice / Recommendations (Verbatim from Final Report)	Recommendation Recipient	(PA Response)	PA Response Notes	Proposed RTR Implementation				
				Choose:	Examples:	Next Steps:	Timeline:	Status:	Notes:	Impacted Programs:
CALMAC ID	Study Name	Recommendations	If incorrect, please indicate and redirect in notes.	Accepted, Rejected, or Other	Describe specific program change, give reason for rejection, or indicate that it's under further review.	For each accepted recommendation, outline the steps required for implementation, responsible parties, and deadlines. For each rejected recommendation, document the reason provided for rejection. Outline any potential follow-up actions or considerations for the future.	Set deadlines for the completion of each action. Include a start date and end date when possible.	Track the status of each action item (e.g., Not Started, In Progress, Completed).	Add notes for any additional information or updates.	Identify which programs (program IDs) would be impacted by the action items.
Overall conclusions and recommendations						**Proposed Next Steps**				
CPU0372.01	PY 2022 Regional Energy Networks Impact	DNV recommends that the PAs (utilities, RENs, and CCAs) and/or their representatives (e.g., technical and regulatory consultants) continue or begin to attend all official coordination meetings as defined in the JCMs even when third-party implementers manage the programs. The PAs should attend the coordination meetings and then direct the program implementers to follow through with any necessary actions identified during the meetings. The PAs should consider including a RACI (responsible, accountable, consulted, informed) chart in the JCMs and PIPs that defines the role of PAs, implementers, and any other stakeholders. A RACI chart would help clarify who needs to attend the coordination meetings, define their role, and help eliminate any confusion related to coordination efforts. The RACI chart should be a living document and an updated version of the RACI could be included with both the JCM and PIP documentation. DNV also recommends that attendance at the meetings be documented and made available to future evaluators.	All RENs, MCE	Accepted	MCE's program staff and/or technical and regulatory consultants currently attend coordination meetings, as described in the Joint Cooperation Memos. MCE has Joint Cooperation Memos with PG&E and BayREN, which outline how program managers and consultants meet on a regular basis to review program changes, prevent double-dipping, and check on data sharing needs. Attendance is taken at these meetings, and can be made available to evaluators upon request. MCE's JCMs and PIPs don't currently have RACI charts dedicated to roles for coordination meetings, but these could be developed, if deemed helpful. The JCMs and PIPs currently specify the roles and responsibilities of PAs, implementers, and other stakeholders.	MCE will review the feasibility of developing RACI charts for both the Joint Cooperation Memos (JCMs) and Program Implementation Plans (PIPs) to further clarify stakeholder roles and responsibilities. If implemented, MCE will coordinate with BayREN and PG&E to align the format and definitions used in the RACI charts. MCE will also explore including these RACI charts as appendices in future JCM and PIP updates to ensure they remain living documents.	Q2 2026 – Evaluate feasibility and develop draft RACI chart framework. Q3 2026 – Coordinate with BayREN and PG&E on alignment and finalize format. Q4 2026 – Include RACI charts in updated JCMs and PIPs.	Planned	MCE's JCMs and PIPs already define key coordination roles and responsibilities. The addition of RACI charts would further enhance clarity but will depend on inter-PA agreement for consistency across documentation.	All energy efficiency programs managed under the Joint Cooperation Memos (including Residential, Commercial, Industrial, Agricultural, and Cross-Cutting).

CEDARS FILING SUBMISSION RECEIPT

The MCE portfolio budget filing has been submitted and is now under review. A summary of the budget filing is provided below.

PA: Marin Clean Energy (MCE)

Budget Filing Year: 2026

Submitted: 14:20 on 27 Oct 2025

By: Qua Vallery

Advice Letter Number: MCE91-E

* Portfolio Budget Filing Summary *

- TRC: 0.87
- PAC: 1.08
- TRC (no admin): 1.46
- PAC (no admin): 2.19
- RIM: 0.3
- SCB: 1.19
- SCH: 1.23
- Budget: $20,215,987.33
- TotalSystemBenefit: $21,689,122.52
- ElecBen: $12,870,060.80
- GasBen: $8,941,103.66
- WaterEnergyBen: $244.79
- OtherBen: $1,000,000.00
- TRCCost: $26,286,342.66
- PACCost: $21,075,306.99
- RIMCost: $89,331,644.44
- SCBCost: $26,896,912.30
- SCHCost: $26,945,829.47

* Programs Included in the Budget Filing *

- MCE01: Multifamily Energy Savings Equity
- MCE01c: Multifamily Strategic Energy Management
- MCE01d: Residential Efficiency Market
- MCE01-R: Multifamily Energy Savings Resource

- MCE02a: Commercial Deemed
- MCE02b: Commercial Custom
- MCE02c: Commercial Strategic Energy Management
- MCE02d: Commercial Efficiency Market
- MCE02e: Small Business Energy Advantage
- MCE08: Single Family Home Energy Savings
- MCE100: Integrated Demand Side Management (IDSM)
- MCE101-Equity-PS: Equity Portfolio Support
- MCE101-MS-PS: Market Support Portfolio Support
- MCE101-RA-PS: Resource Acquisition Portfolio Support
- MCE10a: Industrial Deemed
- MCE10b: Industrial Custom
- MCE10c: Industrial Strategic Energy Management
- MCE11a: Agricultural Deemed
- MCE11b: Agricultural Custom
- MCE11c: Agricultural Strategic Energy Management
- MCE16: Green Workforce Pathways
- MCE97: CPUC EM&V;
- MCE98: MCE EM&V;

CEDARS FILING SUBMISSION RECEIPT

The MCE portfolio budget filing has been submitted and is now under review. A summary of the budget filing is provided below.

PA: Marin Clean Energy (MCE)

Budget Filing Year: 2027

Submitted: 14:21 on 27 Oct 2025

By: Qua Vallery

Advice Letter Number:

* Portfolio Budget Filing Summary *

- TRC: 0.95
- PAC: 1.18
- TRC (no admin): 1.59
- PAC (no admin): 2.39
- RIM: 0.31
- SCB: 1.28
- SCH: 1.31
- Budget: $20,215,987.33
- TotalSystemBenefit: $23,725,981.00
- ElecBen: $13,283,338.93
- GasBen: $9,400,674.54
- WaterEnergyBen: $251.22
- OtherBen: $2,200,000.00
- TRCCost: $26,322,339.61
- PACCost: $21,111,303.95
- RIMCost: $91,410,458.95
- SCBCost: $26,942,470.30
- SCHCost: $26,980,868.35

* Programs Included in the Budget Filing *

- MCE01: Multifamily Energy Savings Equity
- MCE01c: Multifamily Strategic Energy Management
- MCE01d: Residential Efficiency Market
- MCE01-R: Multifamily Energy Savings Resource

- MCE02a: Commercial Deemed
- MCE02b: Commercial Custom
- MCE02c: Commercial Strategic Energy Management
- MCE02d: Commercial Efficiency Market
- MCE02e: Small Business Energy Advantage
- MCE08: Single Family Home Energy Savings
- MCE100: Integrated Demand Side Management (IDSM)
- MCE101-Equity-PS: Equity Portfolio Support
- MCE101-MS-PS: Market Support Portfolio Support
- MCE101-RA-PS: Resource Acquisition Portfolio Support
- MCE10a: Industrial Deemed
- MCE10b: Industrial Custom
- MCE10c: Industrial Strategic Energy Management
- MCE11a: Agricultural Deemed
- MCE11b: Agricultural Custom
- MCE11c: Agricultural Strategic Energy Management
- MCE16: Green Workforce Pathways
- MCE97: CPUC EM&V;
- MCE98: MCE EM&V;

Multifamily Energy Savings Program

Resource Acquisition (MFES01-R)

Implementation Plan

PY2026

September 2025
Version 1

Program Overview

The Multifamily Energy Savings (MFES) Resource Program is designed to deliver cost-effective energy savings in the multifamily sector by expanding access to electrification incentives beyond deed-restricted affordable housing. The program provides technical assistance and incentives to property owners and tenants to support the adoption of high-efficiency electrification measures, with a targeted focus on heat pump HVAC, heat pump water heating, and induction stoves.

The program budget is allocated across administration, implementation, marketing and outreach, and incentives, with the majority directed toward customer incentives and direct implementation activities. Savings will be claimed through deemed, in alignment with CPUC guidance.

By focusing on high-impact, cost-effective measures, the MFES Resource Program supports broader electrification adoption in multifamily properties across MCE's service territory and contributes to decarbonization goals while delivering significant lifecycle savings during the portfolio period.

Program Budget and Savings

1. **Program and/or Sub-Program Name:**
   Multifamily Energy Savings Resource Program

2. **Sub-Program ID number:**
   MCE01-R

3. **Sub-Program Budget Table:**

MCE01-R Budget Categories	2026 Budget
Administration	$9,656.76
Marketing, Education, and Outreach	-

Direct Implementation Non-Incentives	$197,254.04
Incentives	$690,836
Total	**$897,746.80**

4. Sub-program Net Impacts Table:

MCE01-R Impacts	2026 Targets
Net kWh Reduced	-265,885
Net kW Reduced	0
Net Therms Reduced	29,583
Total System Benefits	$470,381

5. Sub-Program Cost Effectiveness (TRC):
   0.69

6. Sub-Program Cost Effectiveness (PAC):
   0.69

7. Type of Sub-Program Implementer (Core, Third Party, or Partnership):
   Third Party

8. Market Sector (including multi-family, low income, etc.):
   Multifamily

9. Sub-program Type (Non-resource, Resource Acquisition, Market Transformation):
   Resource Acquisition

10. Intervention Strategies (Upstream, Downstream, Midstream, Direct Install, Non-Resource, Finance, etc.):
    Downstream

Implementation Plan Narrative

1. Program Description

The MCE Multifamily Energy Savings (MFES) Resource Program is designed to expand access to electrification upgrades for multifamily properties across MCE's service area. While MCE's existing Equity Multifamily Program focuses exclusively on deed-restricted affordable housing and offers a comprehensive suite of incentives, the Resource Program was created to serve a broader segment of the multifamily market.

Drawing on lessons from MCE's experience delivering the Equity Multifamily Program, the Resource Program uses a similar delivery approach but is tailored to meet the needs of properties that may not be ready—or eligible—for a full building retrofit. Instead, the program targets the most impactful and cost-effective measures: heat pump HVAC systems, heat pump water heaters, and induction stoves. By focusing on these measures, the program helps overcome upfront cost barriers and accelerates adoption of electrification technologies in a wider range of multifamily properties.

The MFES Resource Program services include no-cost property assessments, development of project scopes, and ongoing assistance throughout the project lifecycle. Property owners will receive rebates to help offset the cost of electrification upgrades, with program design structured to balance meaningful incentives with cost-effectiveness requirements.

The program's objectives are to:

- Extend access to electrification incentives beyond deed-restricted affordable properties, reaching more multifamily communities in MCE's service area.
- Support property owners in initiating electrification through targeted, high-impact measures.
- Provide customized technical assistance to guide projects from initial assessment through construction.
- Reduce market barriers by bridging the funding gap for electrification retrofits.

2. Program Delivery and Customer Service

<u>Program Implementer Role</u>

The MFES Resource Program is implemented by the **Association for Energy Affordability (AEA)**, a nonprofit organization specializing in energy efficiency for new and existing buildings.

AEA provides technical assistance, project management, and quality control (QC) services to ensure successful project delivery.

Program Delivery Approach

The MFES Resource Program is a downstream program that delivers site-specific recommendations and incentives to encourage adoption of electrification measures. The program focuses on three key measures, heat pump HVAC systems, heat pump water heaters, and induction stoves, selected for their cost-effectiveness and impact.

Each participating property is assigned a Technical Assistant (TA) from AEA who serves as the single point of contact throughout the customer journey. The TA provides:

- Initial engagement through phone calls to gather building information and understand property goals.
- No-cost energy assessments, including onsite verification of building data.
- Technical guidance through contractor bid walks, equipment review, and development of project scope.
- Assistance with incentive reservations and coordination with other funding sources.
- Project closeout services, including installation verification and document collection.

Property owners receive rebates to offset the cost of eligible electrification measures, with program design intended to reduce upfront barriers while providing consistent technical support.

Customer Service and Tools

The program provides a full suite of customer services, including:

- **Targeted outreach** to multifamily property owners and managers.
- **Customized technical assistance** to guide projects from initial assessment through construction.
- **Program navigation support**, helping participants identify and stack incentives from other programs where possible.
- **Quality assurance and verification** to ensure installations meet program specifications.

Partner Program Coordination

MFES Resource will coordinate closely with partner programs to maximize participant benefits and avoid duplication of incentives. TAs will assess whether properties are a better fit for other offerings, and if so, connect them accordingly. When multiple programs are co-leveraged, the TA will ensure that measures are clearly attributed to distinct funding sources, avoiding double-counting and “double dipping.”

Projects that qualify for both MFES Resource and MFES Equity may participate in both programs; however, they may not receive incentives for the same measure from more than one program. This approach ensures clear attribution of savings and incentives while enabling participants to pursue more comprehensive upgrades.

Outreach Strategy

The program's outreach efforts will leverage existing organizational networks and communication channels, including customer contacts, local government partners, industry associations, and property management organizations. AEA will continue to build upon established relationships with affordable housing organizations, multifamily developers, and property owners and managers to extend the program's reach.

Outreach activities will include coordination with:
- BayREN and local government agencies.
- Property-owner and developer organizations.
- Property management companies and service providers.
- Industry professionals such as mechanical engineers and general contractors.

3. Program Design and Best Practices

The MFES Resource Program is designed to reduce market barriers that limit electrification adoption in multifamily buildings while applying best practices informed by MCE's experience implementing the Equity Multifamily Program. By extending access to all multifamily properties, the program addresses challenges unique to market-rate and mixed-income properties while providing a streamlined, customer-centered approach.

Primary Measures Offered

Primary measures incentivized in this program include:
- Heat Pump Water Heating
- Heat Pump Space Heating & Cooling
- Induction Ranges & Cooktops

Additional measures may be added based on available workpapers at the time of program offering.

Market Barriers Addressed

The program is structured to overcome barriers commonly faced by multifamily properties, including:

- Program navigation challenges. Property owners are often unsure which program(s) apply to their property type or project scope. MFES assigns a Technical Assistant (TA) to guide owners through the entire process, from assessment to incentive reservation, ensuring they connect with the most appropriate offerings.
- Limited technical expertise. Many owners lack the tools to evaluate the technical and economic potential of electrification. The TA provides site-specific analyses and practical recommendations to support decision-making.
- Diversity of building stock. Multifamily properties vary widely in size, age, and systems. MFES offers customized technical assistance to tailor recommendations to each property's unique conditions.
- Timing of capital improvements. Energy upgrades are often most feasible during major equipment replacement or refinancing events. MFES recognizes these "trigger points" and aligns program support with them.
- Split incentives. Tenants typically pay energy bills while owners make capital decisions. MFES mitigates this barrier through rebates that reduce owner costs, and by stacking incentives with partner programs where available.
- Perceived disruption and cost concerns (market-rate properties). Market-rate owners may perceive electrification as costly, disruptive, or not aligned with tenant demand. MFES addresses this through simplified participation, meaningful incentives, and TA support that reduces administrative burden.

Program Design and Best Practices

MFES incorporates lessons learned from MCE's Equity Multifamily Program, adapting them to broaden access while maintaining effectiveness. Best practices reflected in this design include:

- Single Point of Contact (SPOC): Each property is assigned a TA to streamline the customer experience and minimize administrative barriers.
- Comprehensive assessment with targeted measures: While incentives focus on the most cost-effective measures, assessments identify additional opportunities and connect owners to other programs.
- Program alignment and referrals: MFES coordinates with BayREN, PG&E, TECH, LIWP and other offerings to maximize customer benefits and avoid duplication.
- Flexible design: By focusing on cost-effective measures and recognizing project timing, MFES accommodates diverse property needs and investment cycles.
- Equity-informed delivery model: While MFES Equity prioritizes higher incentives and resources for lower-income properties that face greater financial barriers, while MFES Resource targets the broader market with moderate incentives, ensuring equitable access and support for market-rate properties.

Through this design, MFES builds on proven strategies while expanding electrification opportunities across the multifamily market, positioning the program as a best-practice model for delivering scalable, customer-focused savings.

4. Program Metrics

The MFES Resource Program will track progress using a combination of property- and unit-level metrics across four key project stages. Given that multifamily projects involve multiple stakeholders and phases that often span several program years, the program will monitor:

a) **Projects Developed:** Number of properties receiving technical assistance, initial assessments, and scope development. This stage captures early engagement and planning activities that prepare a property for participation.
b) **Projects Reserved:** Number of properties with reserved incentives, indicating commitment to proceed with installation.
c) **Projects Under Construction:** Number of properties where installation of program measures has begun.
d) **Projects Completed:** Number of properties and units for which rebates and incentives have been issued, representing completed, verified installations.

Projected Participation – PY 2026		
Project Stages	**Number of Properties**[1]	**Number of Households (Units)**[1]
Developed	1-3	70-120
Reserved	1-2	30-60
Under Construction	1-3 (subtotal)	120
Project Completed	1-3 (subtotal)	120

Table 1: MFES Resource Program Targets

Project Development includes technical assistance to identify, refine, and coordinate installation of scoped measures, spanning from initial interest through construction completion.

Metrics are designed to capture program progress at both the property and unit level, providing visibility into program uptake and measure adoption.

[1] These are not cumulative numbers. Properties and units can go through one or more of these stages within a year.

Supporting Documents

1. Program Manuals and Program Rules

Program Manual attached.

2. Program Logic Model

The logic informing the MCE Multifamily Sub-Program design is aligned with recommendations from industry stakeholders and best practices from existing programs.

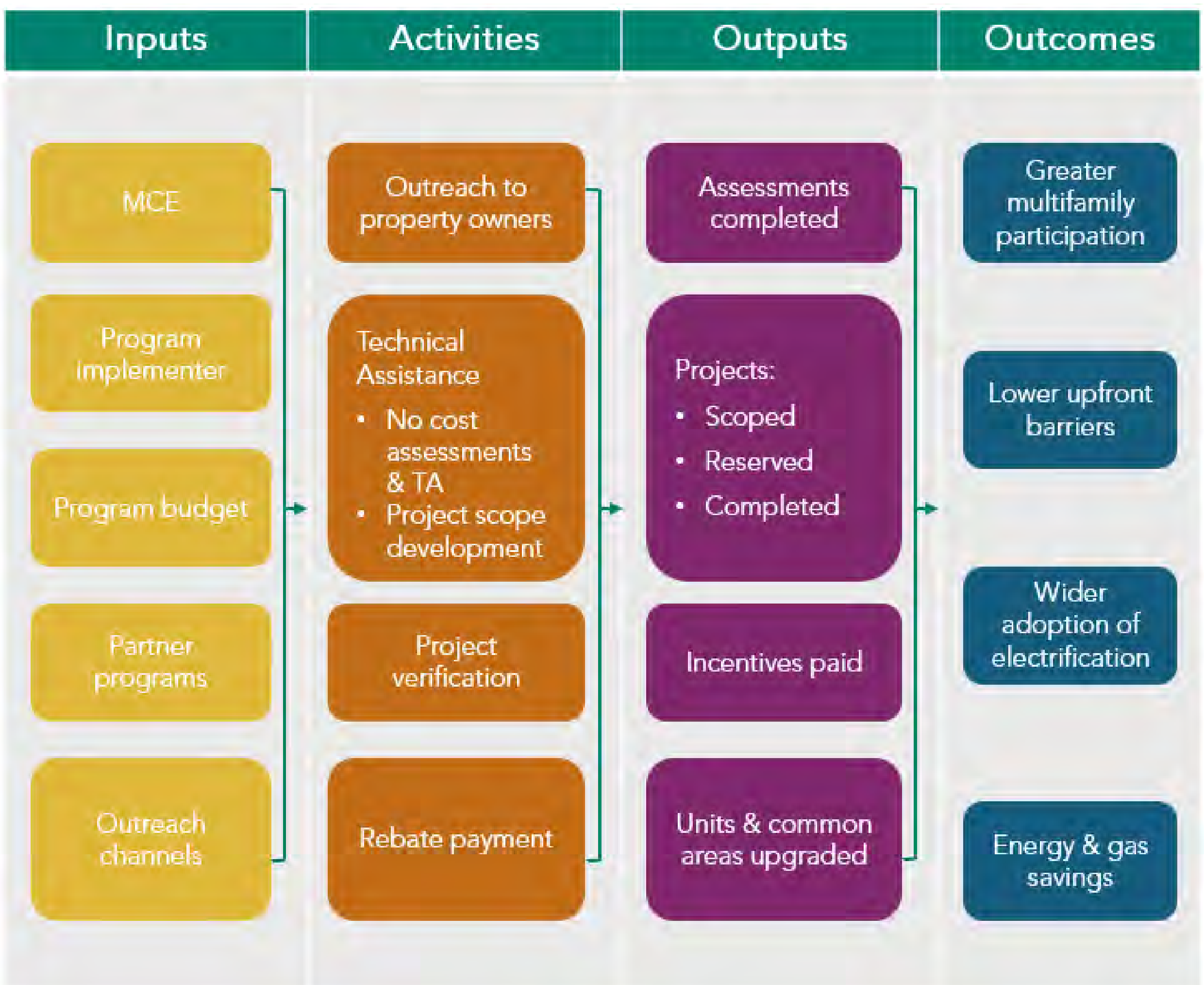


Figure 1: MFES Logic Model

3. Process Flow Chart

AEA's Technical Assistance (TA) and Implementation team follows a structured process when a new applicant applies to the MFES Resource Program. Participants begin by submitting an interest form and completing a brief intake call. If eligible, the program moves forward with a site assessment and energy report to identify opportunities. From there, the project scope is finalized, and incentives are reserved to support installation. Once measures are installed and confirmed through verification, the participant signs off on completion. The process concludes with final documentation and rebate payment.

Throughout these steps, the TA also ensures coordination with other MCE programs and external partners. This prevents duplicative incentives, connects participants to the most appropriate offerings, and streamlines the experience across programs and agencies.

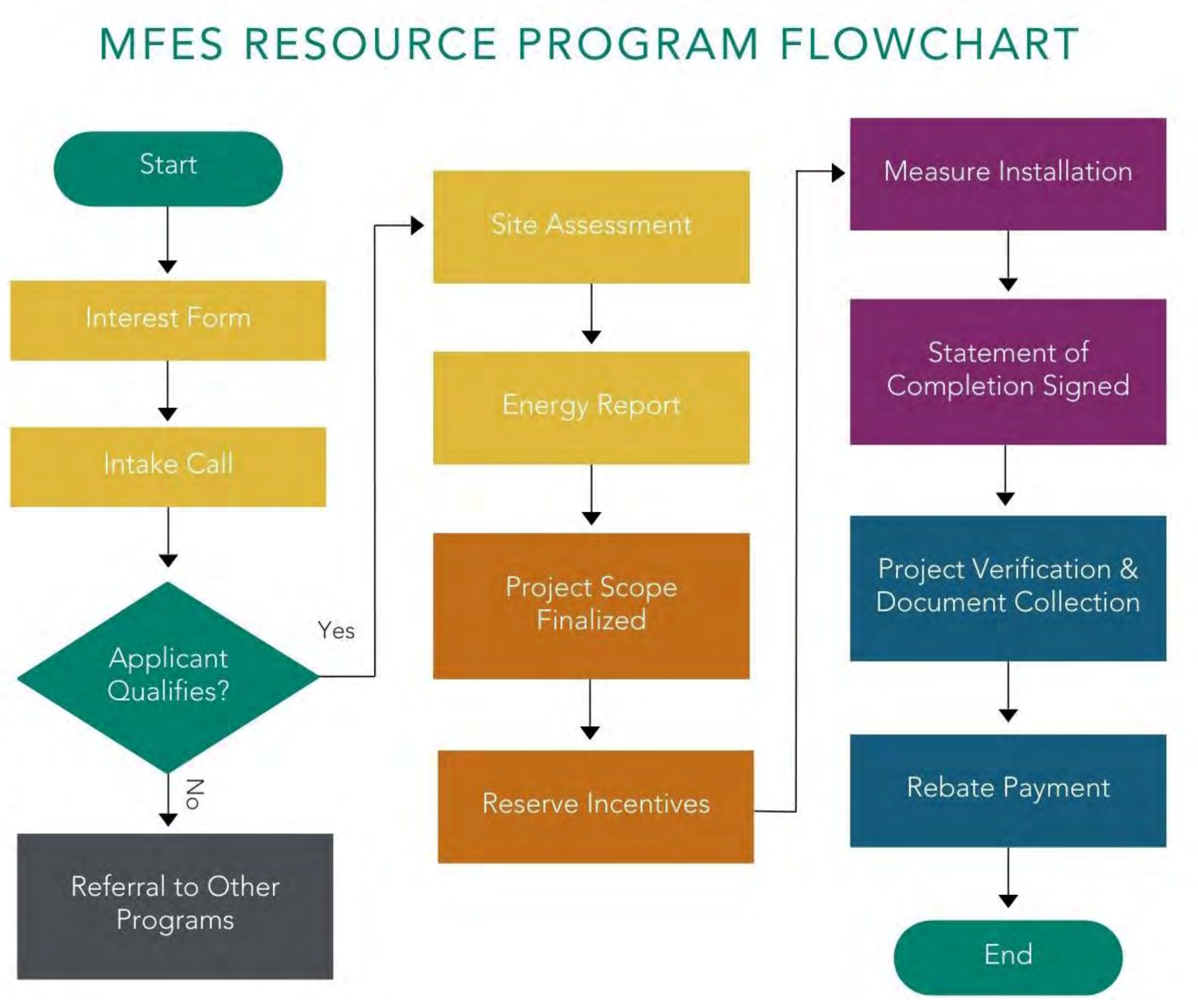


Figure 2: MFES Resource Flowchart

4. Incentive Tables, Workpapers, Software Tools

The MFES Program supports a range of electrification measures in both common areas and in-unit applications. Incentive levels are designed to offset upfront costs and accelerate adoption. Savings will be calculated using deemed values from the Database for Energy Efficient Resources (DEER) or site-specific custom calculations. Additional measures will be incorporated as workpapers are approved.

Program Requirement: To qualify for rebates, existing gas equipment must be fully removed, disconnected, and capped.

Measure Type	Measure	Location	Incentive[2] Level	Workpaper / Tool Reference
Electrification	Heat Pump Water Heater	In-Unit	$3,000 / ea.	Deemed Workpaper
Electrification	Heat Pump Water Heater	Common Area	$3,000 / ea.	Deemed Workpaper
Electrification	Ductless Mini Split	In-Unit	$4,000 /ea. + $500 per ea. additional head	Deemed Workpaper
Electrification	Heat Pump Water Heater	Central	$2,600 / unit served	Deemed Workpaper
Electrification	Package Terminal Heat Pump	In-Unit	$2,200 / ea.	Deemed Workpaper
Electrification	Ducted Heat Pump	Common Area	$3,000 / ea.	Deemed Workpaper
Electrification	Heat Pump Water Heater	Pool	$3,750 / ea.	Deemed Workpaper
Electrification	Induction Range	In-Unit	$1,000 / ea.	Deemed Workpaper

Table 2: MFES Incentives for Common EE Measures

[2] Exact incentive levels to be finalized based on budget allocations and approved workpapers.

5. Quantitative Program Targets

For Program Year 2026, the MFES Resource Program anticipates achieving the following outcomes based on program design and historical participation:

Energy Savings and System Benefits	
Impact Metric	**2026 Target**
Net kWh Reduced	265,885
Net kW Reduced	0
Net Therms Reduced	29,583
Total System Benefits	$470,381

Table 3: MFES Program Targets

Participation

- **Properties and Households**: As tracked through program stages, the program expects to engage 1–3 properties representing 70–120 units, with completed installations in 1–3 properties covering 120 units.
- **Non-Incentive Services:** Technical assistance, assessments, and scope development will be provided as part of the program stages described in the metrics section.

These targets reflect anticipated results based on program design assumptions and historical participation data and are intended to guide annual planning and reporting.

6. Diagram of Program

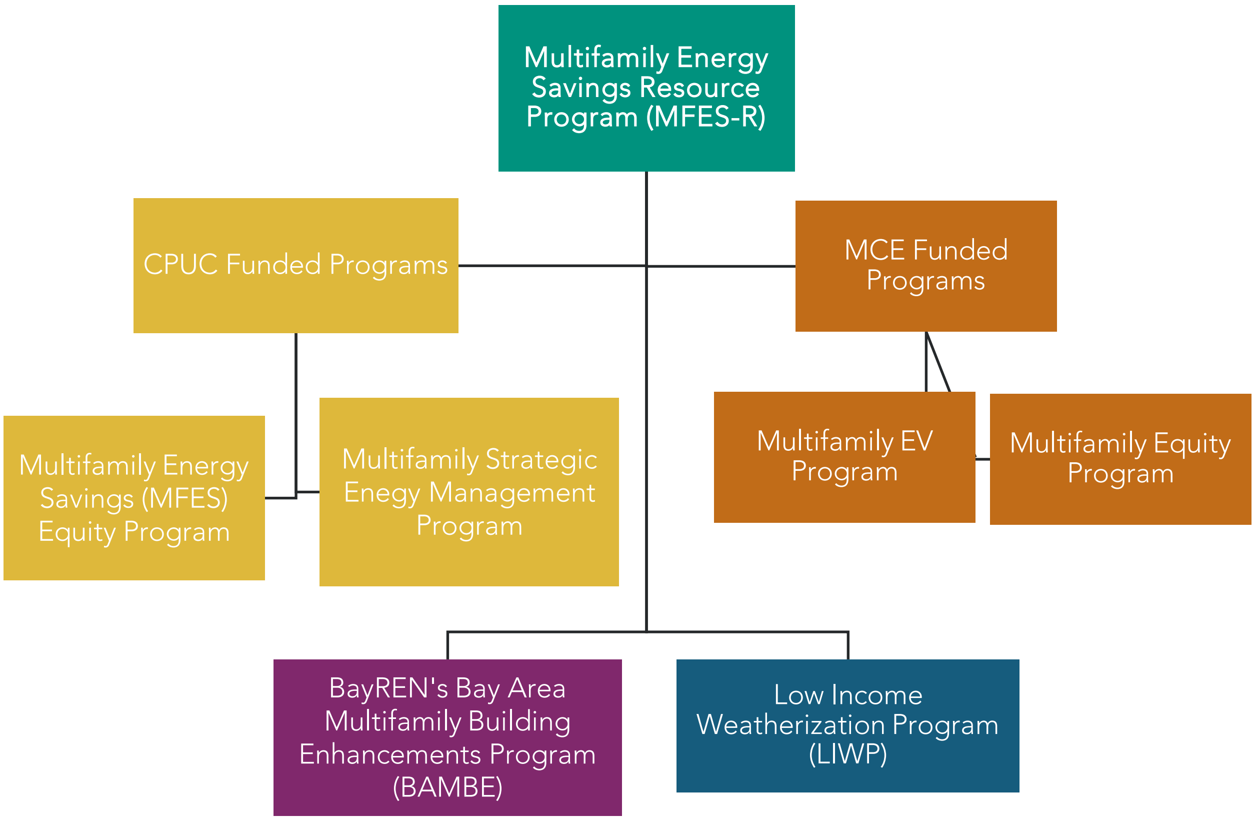


Figure 3: MFES Resource Program Diagram

7. Evaluation, Measurement & Verification (EM&V)

The program will use a combination of deemed measure savings and baseline assessments to determine appropriate workpapers. The Technical Assistant (TA) will visit sites during and after construction to verify that installations are completed across the property. To ensure accurate representation of the building while controlling implementation costs, a sampling of tenant units will be assessed alongside all common area spaces.

QA Activity	QA Sampling Rate (Indicate Pre/Post Sample)	QA Personnel Certification Requirements
Initial Site Visit by Technical Assistant	Sampling of tenant units, 100% of common areas	BPI Accredited

Pre-construction Bid Walks and Mid-construction Site Visits	Sampling of tenant units, 100% of common areas	BPI Accredited
Post Implementation Site Visit by Technical Assistant	Sampling of tenant units, 100% common area installations	BPI Accredited

Table 4: Site Visit QA Requirements

This approach ensures verification of installations and accurate measurement of energy savings while maintaining cost-effective program implementation.

Program Manual

1. Eligible Measures

The program incentivizes cost-effective electrification measures for multifamily properties within MCE service area. Eligible measures include:

- Heat pump HVAC systems
- Heat pump water heating systems
- Induction stoves

Measures must be installed according to program specifications and applicable workpapers. Only installations meeting these technical standards are eligible for program incentives.

2. Customer Eligibility Requirements

Multifamily properties within MCE service area are eligible to participate. Properties must:

- Be residential rental housing, such as multifamily buildings
- Have at least five rental units
- Be existing properties (no new construction)
- Be utility customers of Pacific Gas & Electric (PG&E) or MCE

3. Contractor Eligibility Requirements

Properties may choose the contractor they work with, provided the contractor:

- Holds applicable trade licenses and certifications
- Employs personnel accredited by BPI (or equivalent) for technical assistance and quality assurance activities
- Follows program specifications, reporting, and documentation requirements

4. Participating Contractors, Manufacturers, Retailers, Distributors, and Partners

Not applicable.

5. Additional Services

Not applicable.

6. Audits

Technical assessments are conducted to establish baseline conditions and verify installation of program measures. Key points include:

- **Pre- and Post-Audits:** Conducted as part of program delivery.
- **Scope:** Includes all common areas and a sampling of tenant units to verify energy efficiency and electrification measures.
- **Personnel:** Technical Assistants with BPI accreditation conduct all assessments

7. Sub-Program Quality Assurance Provisions

Quality assurance and quality control activities include:

QA Activity	QA Sampling Rate (Indicate Pre/Post Sample)	QA Personnel Certification Requirements
Initial Site Visit by Technical Assistant	Sampling of tenant units, 100% of common areas	BPI Accredited
Pre-construction Bid Walks and Mid-construction Site Visits	Sampling of tenant units, 100% of common areas	BPI Accredited
Post Implementation Site Visit by Technical Assistant	Sampling of tenant units, 100% common area installations	BPI Accredited

8. Other Program Metrics

Program tracking relies on comprehensive documentation and data collection, including:

- Installation reports and incentive claim forms
- Technical assistance and site visit documentation
- Energy savings calculations using deemed measure savings or site-specific calculations
- Tracking of participating properties, units, and incentive distribution
- Sector- and portfolio-level reporting in alignment with CPUC requirements

Multifamily Energy Savings Resource Program

Launch Webinar

SEPTEMBER 30, 2025

Agenda

- **Program Background:** Multifamily Energy Savings Resource Program Context
- **Program Overview:** Design, budget, implementation details and targets
- **Discussion and Q&A**

Program Background

Why MFES-R?

- Expands access to all multifamily properties (beyond deed-restricted affordable housing)
- Builds on lessons from Equity Program
- Focus on high TRC electrification measures (HP HVAC, HP water heating, induction)
- Support MCE's decarbonization goals

Program Overview

Program Objectives

Extend Access

To electrification incentives to more multifamily properties

Impact Measures

To support properties initiating electrification

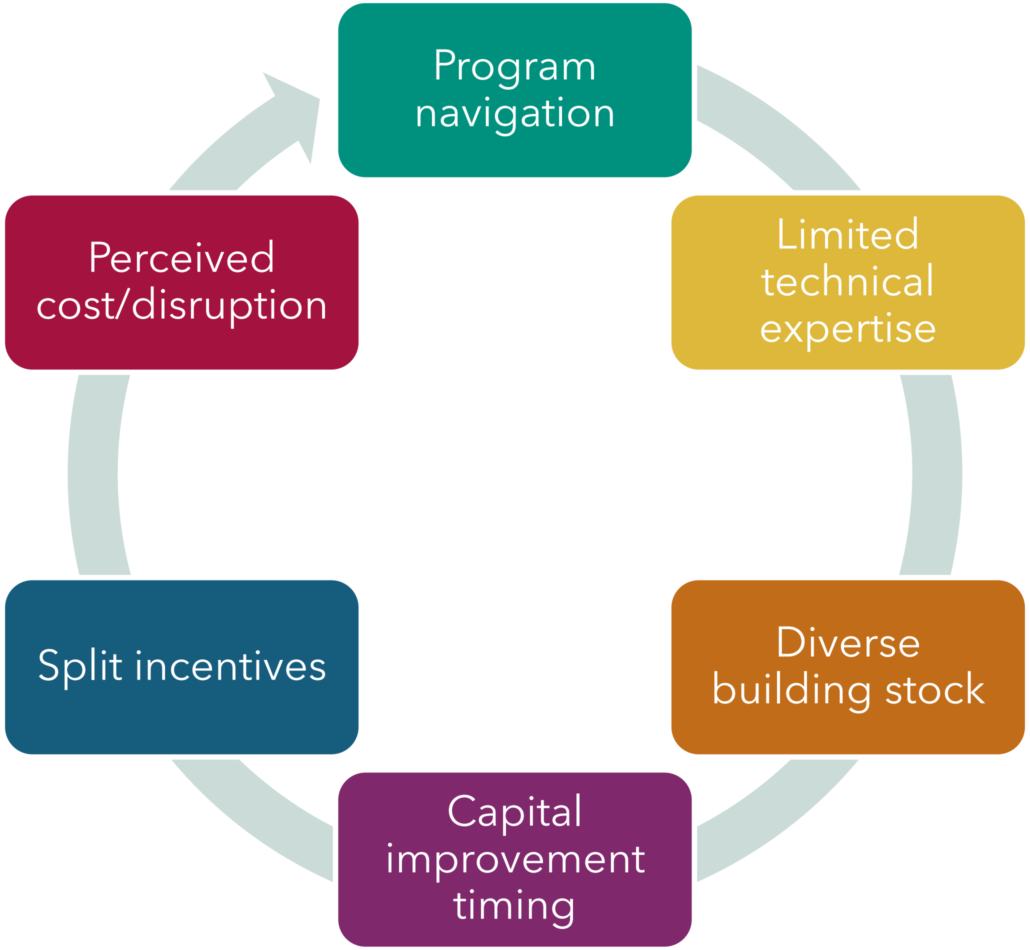
Customized TA

To guide projects from assessment through construction

Reduce Barriers

By bridging funding gap for electrification retrofits

Barriers Addressed by MFES-R



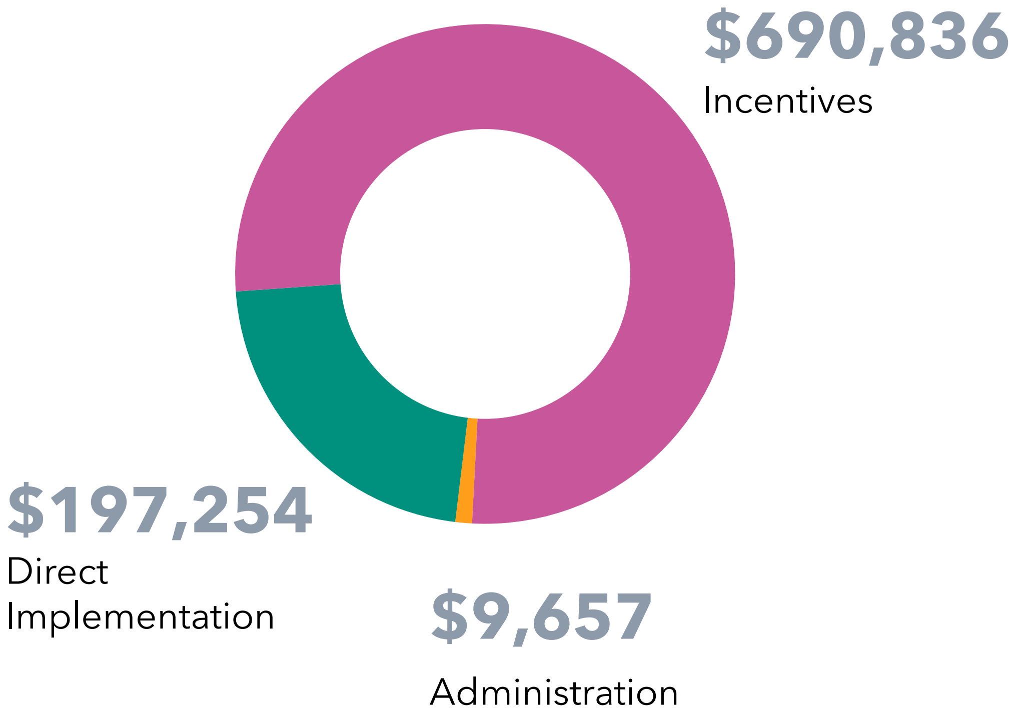
Program Delivery & Customer Service

- **Program Implemented** by AEA
- **Program Delivery**
  - Downstream: Similar customer journey to MFES Equity
  - Rebated Measures: Heat pump HVAC, heat pump water heaters, induction stoves
- **Partner Coordination:** Maximize tenant/property benefits, avoid duplicate incentives, connect properties to best-fit programs
- **Targeted Outreach:** Focus on eligible properties, leverage existing networks

Budget & Incentives

2026 Program Budget

Total: $897,747



Incentives Table

Measure	Location	Incentive*
Heat Pump Water Heater	In-Unit	$3,000 / ea.
Heat Pump Water Heater	Common Area	$3,000 / ea.
Ductless Mini Split	In-Unit	$4,000 /ea. + $500 per ea. additional head
Heat Pump Water Heater	Central	$2,600 / unit served
Package Terminal Heat Pump	In-Unit	$2,200 / ea.
Ducted Heat Pump	Common Area	$3,000 / ea.
Heat Pump Water Heater	Pool	$3,750 / ea.
Induction Range	In-Unit	$1,000 / ea.

* Exact incentive levels to be finalized based on budget allocations and approved workpapers.

Savings and Participation Targets - 2026

Impact Savings	Targets
Net kWh Reduced	-265,885
Net Therms Reduced	29,583
Total System Benefits	$470,381

Project Stage	Number of Properties*	Number of Households / Units*
Developed	1-3	70-120
Reserved	1-2	30-60
Under Construction	1-3 (subtotal)	120
Project Completed	1-3 (subtotal)	120

0.69
TRC

0.69
PAC

* These are not cumulative numbers. Properties and units can go through one or more of these stages within a year.

QA & EM&V

Pre, Mid and Post
Site Visits

BPI
Accredited Staff

Sampling Tenant Units
+
100% Common Areas

Discussion & Q&A

Next Steps

- Public Webinar
- Questions & Feedback by 10/7
  regulatory@mcecleanenergy.org
- Finalize program documentation for MCAL submission
- Prepare for launch 2026 (pending MCAL approval)


MCE
CELEBRATES
15
YEARS OF SERVICE
Thank you!
MCE
Grace Peralta, Senior Customer Programs Manager

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
COMMENTS ON THE ORDER INSTITUTING RULEMAKING

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

November 4, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

California Energy Commission Dockets

California Public Utilities Commission Decisions

California Public Utilities Commission Proceedings

California Public Utilities Commission Rulings

SUMMARY OF RECOMMENDATIONS

In summary, CalCCA recommends that the Commission:

- Address RA SOD transactability issues, as scoped in the OIR, with a modified schedule to allow parties to file updated proposals following the release of the Energy Division report on transactability issues in Q1 2026;
- Include load forecasting issues within the scope to improve processes with the CEC to increase transparency, collaboration, and certainty in the demand forecast, adjustment, and allocation processes, especially considering the emergence of new data centers and other large loads in the forecast;
- Clarify how local RA CPEs are intended to use the aggregated results of LSEs' local RA data request responses in their procurement decisions;
- Consider within this proceeding updates to the Commission's requirements for showing MIC to align with the SOD framework; and
- Include DR, DER, and microgrid counting rules within the scope of this proceeding.

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
COMMENTS ON THE ORDER INSTITUTING RULEMAKING

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[2] in response to the *Order Instituting Rulemaking*[3] (OIR), issued October 15, 2025, and the directives therein.

I. INTRODUCTION

The Commission's Resource Adequacy (RA) program plays an important role in shaping load serving entities' (LSE) forward capacity procurement to support reliable operations of the California Independent System Operator (CAISO) balancing authority area (BAA). This new rulemaking will continue the Commission's oversight over and make refinements to the RA program. CalCCA

---

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[3] *Order Instituting Rulemaking*, Rulemaking (R.) 25-10-003 (Oct. 15, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M583/K934/583934825.PDF.

supports the scope advanced in the OIR, which includes the following issues: (1) adoption of local capacity requirements; (2) adoption of flexible capacity requirements; (3) loss of load expectation (LOLE) study; (4) accreditation for long-duration energy storage (LDES); (5) unforced capacity ; (6) accreditation for solar and wind resources; (7) transactability issues within the slice-of-day (SOD) framework; (8) residual unit commitment for RA resources; (9) coordination with the Integrated Resource Planning proceeding; and (10) other refinements to the RA program.

The OIR asks parties to "identify no more than five (5) issues relating to refinements to the RA program that it believes should be addressed in this proceeding and list the issues in priority order."[4] CalCCA provides the following five priority issues, as described in detail in these comments. *First*, the Commission should address **RA SOD transactability** issues in this proceeding. CalCCA's analysis submitted in R.23-10-011 demonstrates significant affordability benefits to increasing the transactability of the RA SOD program.[5] CalCCA appreciates the Commission including transactability issues in the scope of this proceeding to consider Energy Division's evaluation of the needs, benefits, and feasibility of hourly load obligation trading as authorized in Decision (D.) 25-06-048.[6] The Commission should modify the schedule in the OIR to allow parties to file modified proposals following the release of the Energy Division report on transactability issues.

Second, the Commission should update the scope of this proceeding to include **RA load forecast** issues. The Commission's process for working with the California Energy Commission (CEC) and LSEs to establish individual LSE RA requirements could benefit from increased transparency, collaboration, and certainty, especially considering the emergence of new data centers

---

4 OIR, at 5.

5 *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025), at 8-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K679/553679242.PDF.

6 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): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF.

and other large loads in the forecast. In addition, the RA program would benefit from more transparent demand allocation procedures that recognize the role each type of LSE plays in serving load and clear procedures for adjustments to individual LSE demand forecast allocations, and adjustments to the overall forecast.

Third, the Commission should clarify how local RA central procurement entities (CPE) are intended to use the aggregated results of LSEs' **local RA data request** responses in their procurement decisions. The September 19, 2025, Annual Compliance Reports from the CPEs suggest that the CPEs used the results to inform their local RA procurement in different ways.[7] The Commission should use this proceeding to clarify how CPEs should use the results to inform reliable and cost-effective local RA procurement that does not require CPEs to over-procure local RA.

Fourth, the Commission should update the scope of this proceeding to coordinate with the CAISO on aligning the Commission's requirements for showing **maximum import capability (MIC) with the SOD framework.** The Commission has updated the requirements for showing fully or partially deliverable co-located resources located within CAISO system to align with SOD, in which either component can count for RA so long as the showing does not exceed the deliverability at the interconnection point in any hour. Similar updates should be considered for imports to ensure imports can provide their full amount of RA in each hour under the SOD program.

Fifth, the Commission should update the scope of this proceeding to include **demand response (DR), distributed energy resource (DER), and microgrid counting rules**. To the extent these issues

---

[7] *See* Advice Letter (AL) 7704-E, *Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") 2025 Annual Compliance Report* (Sept. 19, 2025) (PG&E CPE Annual Compliance Report): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7704-E.pdf; *see also* AL 5632-E, *Southern California Edison Company's 2026 Central Procurement Entity Annual Compliance Report* (Sept. 19, 2025) (SCE CPE Annual Compliance Report): https://www.sce.com/wps/portal/home/regulatory/advice-letters.

are already scoped into another proceeding (*e.g.*, R.25-09-004), the Commission should coordinate the proceedings to ensure consistent rules and effective dates that align with RA showing timelines.

In summary, CalCCA recommends that the Commission:

- Address RA SOD transactability issues, as scoped in the OIR, with a modified schedule to allow parties to file updated proposals following the release of the Energy Division report on transactability issues in Q1 2026;
- Include load forecasting issues within the scope to improve processes with the CEC to increase transparency, collaboration, and certainty in the demand forecast, adjustment, and allocation process, especially considering the emergence of new data centers and other large loads in the forecast;
- Clarify how local RA CPEs are intended to use the aggregated results of LSEs' local RA data request responses in their procurement decisions;
- Consider within this proceeding updates to the Commission's requirements for showing MIC to align with the SOD framework; and
- Include DR, DER, and microgrid counting rules within the scope of this proceeding.

II. RECOMMENDED SCOPE PRIORITIZATION AND SCHEDULE MODIFICATIONS

A. The Commission Should Prioritize the RA SOD Transactability Scope Item and Modify the Schedule to Allow Parties to File Modified Proposals Following the Release of Energy Division's Report

CalCCA appreciates the Commission including RA SOD transactability issues within the scope, and recommends this issue be the highest priority in this proceeding. CalCCA's analysis of 2025 year-ahead RA filings submitted in R.23-10-011 demonstrates significant affordability benefits to increasing the transactability of the RA SOD program.[8] Since then, CalCCA has issued a whitepaper further documenting the benefits of hourly trading by simulating competitive market trades between LSEs.[9] CalCCA has also performed additional analysis on 2025 month-ahead RA showings from CCAs demonstrating that, averaged across five peak summer months, CCAs in aggregate

---

8 *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025), at 8-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K679/553679242.PDF.

9 *See* CalCCA, *Effective Mechanisms for Slice-of-Day RA Trading* (Apr. 24, 2025): https://cal-cca.org/wp-content/uploads/2025/04/4.24.25_Effective-Mechanisms-for-Slice-of-Day-RA-Trading.pdf.

purchased about 540 megawatts (MW) more RA capacity each month than they would have needed had a mechanism like hourly load obligation trading been available.[10] At the 2025 final RA market price benchmark,[11] those excess purchases cost CCA consumers more than $30 million in the summer of 2025. If the tight market conditions observed in the summer of 2024 arise again, as suggested by the Commission's recommendation for additional procurement in R.25-060-019,[12] RA prices could rise again to the levels observed in 2024. The CCAs' excess RA purchases valued at the 2024 RA prices described in CalCCA's whitepaper[13] would cost CCAs customers nearly $51 million. Using similar assumptions about the indirect price reduction effect from lowering RA demand and the potential benefit of hourly obligation trading across all Commission-jurisdictional LSEs, CalCCA's findings from the 2025 month-ahead RA data suggest hourly obligation trading could save all LSEs $144-$179 million each year. These savings could then directly improve affordability for ratepayers.

CalCCA looks forward to reviewing Energy Division's report on the needs, benefits, and feasibility of hourly load obligation trading as authorized in D.25-06-048. The OIR does not specify a date for the issuance of the report beyond Q1 2026. Therefore, the report could come out shortly

---

[10] To quantify the excess RA capacity that could have been avoided with hourly obligation trading, CalCCA first calculated the amount of thermal capacity each individual CCA could have sold from their final month-ahead portfolio, while still remaining compliant. To perform this calculation, CalCCA adjusted the way that an individual CCA would show its contracted storage capacity such that it maximized the amount of thermal capacity that could be removed. Next, CalCCA aggregated all CCA portfolios and requirements, and recalculated the excess thermal capacity from the aggregate showing. The aggregation is a proxy for what could be achieved through frictionless trade between LSEs, which is enabled through a policy like hourly load obligation trading. Finally, the excess RA capacity that could be avoided through hourly obligation trading was calculated as the difference between the excess of the aggregate and the excess for individual CCAs. On average across the five peak months from May to October, CalCCA observed 540 MW of excess thermal capacity that could have been avoided with hourly obligation trading.

[11] CPUC Energy Division. Market Price Benchmark Calculations 2025 (Oct. 1, 2025).

[12] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, R.25-06-019 (Sept. 30, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M582/K082/582082526.PDF.

[13] *See* CalCCA, *Effective Mechanisms for Slice-of-Day RA Trading* (Apr. 24, 2025): https://cal-cca.org/wp-content/uploads/2025/04/4.24.25_Effective-Mechanisms-for-Slice-of-Day-RA-Trading.pdf.

before proposals are due, after comments and reply comments are due, or somewhere in between. The Commission should modify the schedule to ensure parties can file updated proposals, comments, and reply comments based on the contents of Energy Division's report in the event the release of the report does not align with the rest of the schedule for proposals, comments, and reply comments established in the OIR.

B. This Proceeding Should Include Load Forecasting Issues in Scope

The Commission should coordinate with the CEC to increase transparency, collaboration, and certainty in the demand forecast, adjustment, and allocation processes used to set LSEs' RA requirements. These processes must be re-evaluated in the context of the unprecedented increased load predicted in the Demand Forecast established by the CEC's 2024 Integrated Energy Policy Report (IEPR) Update.[14] This increase is driven in large part due to data centers, other large loads, and electrification. The CEC,[15] other state and federal regulators,[16] researchers,[17] and the media have widely noted the difficulty of concluding whether these loads will materialize.

---

[14] CEC 24-IEPR-01, adopted 2024 IEPR Update (Oct. 29, 2025): https://www.energy.ca.gov/publications/2024/2024-integrated-energy-policy-report-update.

[15] CEC Docket No. 24-IEPR-03, Data Center Forecast presentation, Jenny Chen (Dec. 23, 2024), at 2: https://www.energy.ca.gov/sites/default/files/2024-12/Data_Center_Forecast_Update_ada.pdf: CEC staff acknowledged the uncertainties involved with their data center certainty analysis, 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."

[16] For example, a recent letter to regional transmission organizations and independent system operators including the CAISO, from Federal Energy Regulatory Commission (FERC) Chairman Rosner highlights 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.").

[17] *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.").

These large load changes and their uncertainty can significantly affect the grid as a whole and individual LSEs. Failures in accuracy and timeliness, failure to account for the onsite generation of some data centers, or failure to account for the inherent uncertainty with these loads can result in significant consequences for specific LSEs. Large load customers changing their LSE on short notice could also significantly affect LSEs and their procurement. Too high a forecast could result in substantial procurement costs with little or no additional load to spread those costs. With too low a forecast, the LSE's RA requirements could be too low to meet reliability needs. In addition, depending on how the RA obligations are allocated, specific LSEs may be especially impacted.

The CEC's 2024 IEPR Update states:

> Data centers will remain an area of focus for the 2025 IEPR forecast. Staff will continue to track new information, collaborate with utilities to monitor applications for new data centers, and ask for stakeholder feedback on inputs and assumptions. Staff will adjust inputs and assumptions for the 2025 IEPR forecast based on the most recent data.[18]

To this end, the Commission should coordinate with the CEC to hold a workshop(s) to ensure that the IEPR load forecast process and its use for RA purposes provides an accurate and timely load forecast. This process should aim to identify all sources of data that will enable highly accurate load forecasting, providing the maximum amount of time for all LSEs to provide input into their forecasts, and to adjust procurement to the accurate forecast.

The Commission and CEC's approach to load forecasting and RA requirement setting should also establish parameters for at what point to include data center and other loads in forecasts used to determine procurement obligations, given the potentially speculative nature of these loads. Given that data center loads are uncertain and cannot be made more certain even with very careful forecasting, the approach to forecasting and directing procurement for data center load needs to be carefully

[18] 2024 IEPR Update, at 21.

crafted. The Commission should examine ways in which it can ensure a reasonable procurement program that may, in part, be based on speculative large loads such as data centers.

For example, the load forecast process should include a meaningful way for LSEs to dispute the forecast if they identify inaccurate load additions. Currently, the IEPR process is a zero-sum game. That is, to the extent one LSE changes its load forecast, the CEC adjusts other LSEs' forecasts in an equal and opposite direction. This process ensures that the total system wide load forecast remains unchanged. However, this may also not result in the best and most accurate estimates. The Commission and CEC should consider how best to address individual load forecast adjustments and their relationship to the system forecast as a whole, as noted in CalCCA's comments in the 2025 IEPR docket in which it recommends the CEC establish a focused procedural track to improve system demand forecasting and allocation.[19]

C. The Commission Should Clarify the Intended Use of the Local RA Data Request Responses in CPE Procurement Decisions

The Commission should clarify how CPEs should use the local RA data request responses in their procurement decisions to ensure reliable and cost-effective local procurement that does not result in over-procurement when LSE procurement meets local needs. D.24-12-003 adopted a local RA data request process to replace the non-compensated self-showing options. Energy Division provides aggregated local RA procurement information from LSEs to the CPEs so the CPEs can better assess "the state of the overall local portfolio" and "…the actual needs for short-term and long-term procurement for the three-year forward requirements and beyond."[20] The local RA data request process took effect in January 2025 for the 2026 RA compliance year. PG&E Annual Compliance

---

19 *See* CEC Docket No. 25-IEPR-03, *California Community Choice Association's Comments on the August 6, 2025, IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions* (Aug. 20, 2025): https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=25-IEPR-03.

20 D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 5, 2024), at 38: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M549/K295/549295013.PDF.

Report and SCE Annual Compliance Report documented how each CPE took in to account the results of the data request in their procurement decisions.

The PG&E Annual Compliance Report states that:

> Although this data does not count towards PG&E CPE's compliance needs, PG&E CPE used the data to inform its procurement decisions [REDACTED]. Without taking into account the LSE data aggregation results, following the 2025 PG&E CPE procurement efforts, the PG&E CPE has not been able to procure enough capacity to meet the needs in all months for any of the seven (7) local capacity areas within its territory and will be deferring procurement to CAISO backstop mechanisms for those areas for a majority of the months of the 2026 and 2027 compliance years.[21]

The SCE Annual Compliance Report states that:

> This [Annual Compliance Report] demonstrates that SCE-CPE met the obligations set forth in D.20-06-002, D.20-12-006, D.22-03-034, and D.24-12-003. SCE-CPE did not select any offers for its 2025 SCE-CPE Local RA Request for Offers (RFO), as the CPUC Data Request File indicates sufficient local resources in the LA Basin (LAB) and Big Creek Ventura (BCV) local areas that are currently under contract. In short, the CPUC Data Request File demonstrates existing contracted capacity in excess of the Local Capacity needs identified in the CAISO technical studies for SCE-CPE's compliance obligations for years 2026-2028.[22]

These statements show that the two local RA CPEs appear to use the results of the data request differently. SCE's approach appears superior, because accounting for LSE contracts for resources in local areas would limit over-procurement, therefore, offering ratepayer savings. SCE used the data request results to determine whether CPE plus LSE procurement resulted in sufficient local resources under contract. It is unclear how PG&E used the data request results, as PG&E states that the results "informed" its procurement but not its compliance needs. While not clear from the PG&E Annual Compliance Report whether accounting for LSE contracts for resources in local areas would have

[21] PG&E CPE Annual Compliance Report, Public Attachment E, at 3-4.
[22] SCE CPE Annual Compliance Report, Public Attachment 1, at 4.

covered all the PG&E CPE's deficiencies, it appears that even if they had, the PG&E CPE may have still conducted procurement because it did not account for the LSE data aggregation results. This could have resulted in excess and unnecessary procurement costs. The Commission should clarify within this proceeding how CPEs should use the local RA data request responses in their procurement decisions, so the CPEs can use the information consistently and cost-effectively.

D. The Commission Should Update its Requirements for Showing MIC to Align with the SOD Framework

The Commission should coordinate with the CAISO to consider in this proceeding how to align its requirements for showing MIC to align with the SOD framework and provide the full amount of RA in each hour. The advent of the SOD framework has made some RA accreditation rules considerably more complex. This is particularly true for interfaces between the Commission's and CAISO's processes. The CAISO has continued to evaluate RA as a single value on the peak day of the month while the Commission evaluates all hours on the "worst day" of the month. In doing so, the CAISO continues to perform a single hour evaluation, using variable resources' exceedance values in that hour because they no longer have an ELCC value, to determine if there is an RA deficiency that the CAISO must backstop.

These complications have also extended to the general concept of deliverability, which is measured by full or partial deliverability for resources interconnected to the CAISO-controlled grid and by MIC for imports to the CAISO controlled grid. Within the context of deliverability internal to the CAISO grid, the Commission has allowed co-located resources with full or partial deliverability status to count for RA where they do not exceed the deliverability at the interconnection point in any hour of shown RA.[23] This has enabled both the storage component and the co-located generating resource, typically a renewable generator, to both count for reliability. This recognizes that in an RA

[23] D.25-06-048, Ordering Paragraph 10.

showing, the storage component and the generating component are not being shown in the same hours and the deliverability can effectively serve both resources to count for reliability.

The same issue occurs for certain imports. It is possible that an LSE will contract with a renewable resource and storage outside of the CAISO and use those resources in different hours to meet their reliability needs. If done similarly to internal co-located resources as described above, both resources could meet reliability needs while being deliverable to any load on the grid.

The Commission should therefore coordinate with the CAISO to consider in this proceeding how MIC can be more efficiently used to provide the full amount of RA in each hour. This may include allowing an LSE to use the MIC for multiple resources, allowing entities to optimize the use of MIC across all hours, provided the resources are not shown in the same hours in excess of the MIC available. It could also include a mechanism to trade MIC or load obligations hourly so that entities can make the best use of MIC in all hours under SOD.

In addition, CAISO has scoped MIC allocation issues into its RA Modeling and Program Design initiative. Should the CAISO make changes in that process, this proceeding should consider the implications of any such changes on the Commission's program.

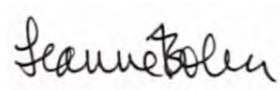
E. The Commission Should Include DR, DER, and Microgrid Counting Accreditation in the Scope of this Proceeding

The scope of this proceeding should include DR, DER, and microgrid accounting. The evolution of the RA program to SOD and the expected proliferation of these resources in the near future necessitate the revisiting or developing of accounting methodologies to ensure they align with the current RA program and provide RA value to new resources coming onto the system. To the extent these issues are already scoped into another proceeding (*e.g.,* R.25-09-004), the Commission should coordinate these proceedings to ensure consistent rules and effective dates that align with the RA showing timeline.

III. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

November 4, 2025