BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	**Rulemaking 18-12-006** **(Filed December 13, 2018)**

**CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION,
ENERGY PRODUCERS AND USERS COALITION
JOINT PETITION FOR MODIFICATION OF D. 22-11-040**

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Pursuant to Rule 16.4 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the California Large Energy Consumers Association (CLECA)[1] and the Energy Producers and Users Coalition[2] (collectively, Petitioners) jointly submit this Petition for Modification (Petition) of Decision (D.) 22-11-040, *Decision on Transportation Electrification Policy and Investment* (Decision).[3]

The Decision adopted a long-term transportation electrification (TE) policy framework (TEF) to address a multitude of issues related to TE investments made by California's investor-

[1] CLECA member companies produce goods essential for daily life, including critical infrastructure, oxygen for hospitals, and food distribution. CLECA members represent the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries. Their aggregate electrical demand exceeds 500 Megawatts, which is equivalent to the electricity consumption of approximately 470,000 average California households. CLECA members are large, high load factor and high voltage industrial electric customers in California for whom the price of electricity is essential to their competitiveness and for whom the reliability of electricity service is critically important. For both reasons, CLECA member companies have participated for decades in the Base Interruptible Program (BIP), providing reliability demand response to the grid in times of need.

[2] EPUC represents the electricity end-use interests of the following companies in this proceeding: California Resources Corp., Chevron U.S.A. Inc., PBF Holding Company, Phillips 66 Company, and Tesoro Refining & Marketing Company LLC.

[3] Issued November 21, 2022.

owned utilities (IOUs). Concerning the cost recovery mechanism for those investments, the Decision ordered the IOUs to record behind-the-meter (BTM) TE program costs as expenses and recover those costs through distribution rates allocated on an equal cents per kilowatt hour (kWh) basis applied equally to all customer classes. [4] Petitioners request that the Commission modify the Decision by replacing the equal cents per kWh cost allocation methodology with a system average percent change (SAPC) methodology. The requested modification is needed to align the TEF with the state's broader electrification and climate goals, and to address growing reliability constraints. This Petition proposes specific wording to carry out the requested modifications, and is supported by new and changed facts, detailed herein, which are judicially noticeable.

I. INTRODUCTION AND BACKGROUND

The Decision establishes Funding Cycle 1 (FC1), a $1 billion-budgeted 5-year program set to launch in 2025, that is primarily focused on providing rebates for BTM TE charging infrastructure. FC1 will be administered by a third party and funded by the IOUs, each of which will contribute its pro-rata share of the $1 billion based on its percentage share of forecasted 2024 electric sales. The Decision orders the IOUs to "record all BTM TE program costs . . . and recover them through distribution rates" on an equal cents per kWh basis.[5] The Commission reasoned that this cost allocation approach will "[help] ensure that costs are distributed across all customer classes equitably."[6]

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[4] Decision at pp. 227-228.
[5] Decision at pp. 50-51.
[6] *Id*.

The Decision is intended to "provid[e] a unified policy-driven funding structure for utility transportation electrification" that helps advance the state's decarbonization goals and supports widespread TE.[7] However, the Decision's adopted cost allocation methodology ultimately serves to hinder these objectives, due to its distortion of price signals in rates which are intended to incent customer behavior that aligns with the state's broader policy objectives. Price signals, which are linked to marginal costs, are a key component of existing time-of-use rates, and will play a key role in advancing the Commission's demand flexibility goals. The equal cents per kWh methodology is a blunt instrument that distorts price signals by allocating TE costs based on usage, regardless of when consumption occurs, ignoring the cost-causative linkage with time-of-use. Furthermore, although the Decision aims to establish a BTM TE cost allocation method that ensures "equitable" distribution of costs, the suggested equal cents per kWh allocation is not equitable, as it imposes a disproportionate burden on large, high load factor customers on a non-time-of-use basis.

To address this misalignment with key policy goals, Petitioners request that the Commission modify the Decision to change the adopted cost allocation methodology from an equal cents per kWh basis to a System Average Percent Change (SAPC) basis. Specifically, Petitioners seek to modify the Decision's cost allocation methodology reflected on page 51 of the Decision, Finding of Fact (FoF) 10, Conclusion of Law (CoL) 11, CoL 125, Ordering Paragraph (OP) 3, and OP 13.

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[7] *See* Decision at pp. 2-3; Press Release "CPUC ADOPTS TRANSPORTATION ELECTRIFICATION PROGRAM TO HELP ACCELERATE ELECTRIC VEHICLE ADOPTION," November 17, 2022 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M498/K953/498953325.PDF).

As Petitioners have noted in this proceeding, SAPC preserves price signals by allocating TE costs through the application of the same average percent change to each customer class. As set forth below, requiring the IOUs to recover TE program costs through distribution rates allocated on a SAPC basis conforms to the recently revised electric rate design principles (ERDPs), and encourages customer behavior that more closely aligns the Decision with the state's reliability and decarbonization goals.

The new and changed facts that support the proposed modification include: the Commission's recent revisions to ERDPs, which were adopted in D.23-04-040;[8] the increased importance of customers' responsiveness to rates, due to the reliability challenges posed by capacity constraints, as reflected in D.23-02-040; [9] and the Decision's disproportionate burden on large industrial customers, as reflected in the IOUs' Advice Letter filings.

II. JUSTIFICATION FOR REQUESTED RELIEF: NEW AND CHANGED FACTS

The requested modifications in this petition are justified by multiple new facts that developed after the Decision's adoption, and several facts that changed since its adoption. The factual allegations in this petition are supported with specific citations to matters that may be officially noticed.[10] Pursuant to Rule 13.10, the Commission may take official notice per

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[8] *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, R. 22-07-005, Apr. 27, 2023.

[9] *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Processes*, R. 20-05-003, Feb. 23, 2023.

[10] *See* Rule 16.4 (b) ("Any factual allegations must be supported with specific citations to the record in the proceeding or to matters that may be officially noticed. Allegations of new or changed facts must be supported by an appropriate declaration or affidavit.").

Evidence Code Section 450, et seq.[11] California Evidence Code Section 452(c) permits judicial notice of "[o]fficial acts of the legislative, executive, and judicial departments" of this state.[12] "Official acts include records, reports and orders of administrative agencies."[13] With respect to taking official notice as to matters on a website, courts have taken judicial notice if it is the website of a party or a government agency, and not subject to interpretation.[14] Further, Evidence Code Section 452(h) permits judicial notice of "[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy."[15] These facts justifying the requested modifications are discussed below.

A. The Recently Updated Electric Rate Design Principles Reflect that Rates Must Minimize Price Signal Distortions

The Commission's Demand Flexibility rulemaking proceeding (R.22-07-005) seeks to "enable widespread demand flexibility through electric rates," by establishing demand flexibility policies and modifying rates to advance various policy objectives.[16] Those objectives include enhancing electric system reliability, and enabling widespread TE to meet the state's climate goals.[17] Notably, the Commission's demand flexibility efforts rely on achieving those

[11] *See* D. 19-08-040 at 4 ("Evidence Code section 452 allows for judicial notice of public entity regulations and legislation, court records, and indisputable facts, which either are common knowledge or can be verified by reasonably indisputable sources.").
[12] Evid. Code, § 452(c).
[13] *See Ordlock v. Franchise Tax Bd*. (2006) 38 Cal.4th 897, 911, fn.8. (*citing Rodas v. Spiegel* (2001) 87 Cal.App.4th 513, 518).
[14] *See* D. 16-01-014 at p. 21.
[15] Evid. Code, § 452(h).
[16] *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, R. 22-07-005, Jul. 22, 2022 at p. 1.
[17] *Id.*

objectives through rates that incorporate universally accessible, dynamic, and economic signals intended to incent customer behavior.[18]

On April 27, 2023, the Commission adopted D.23-04-040, which revised and modernized ERDPs used for assessing electric rate design proposals of the IOUs across customer classes.[19] The revisions were intended to align the ERDPs with current state goals and guide the development of demand flexibility tariffs.[20] These recent revisions support the Petition's proposed modification to allocate TE costs on a SAPC basis, since they reflect the importance of preserving price signals in rates to achieve demand flexibility goals.

In D.23-04-040, the Commission adopted ERDP 4, which provides that "[r]ates should encourage economically efficient (i) use of energy, (ii) reduction of GHG emissions, and (iii) electrification."[21] Notably, the Commission stated that the updated principle:

> reflects several of the state's current policy priorities, including reduction of GHG emissions by shifting consumption of electricity to time periods when the grid is supplied predominantly by GHG-free resources and electrification of transportation and buildings to reduce GHG emissions.

The Decision's equal cents per kWh cost allocation methodology violates this updated principle by distorting price signals needed to encourage customer consumption that supports the state's policy objectives. In contrast, SAPC can help to preserve time-variant rate price signals intended to discourage consumption during high cost or high GHG-emissions periods.

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[18] *See*, *id.,* at p. 6.
[19] D.23-04-040 at p. 7.
[20] D.23-04-040 at FoF 2, CoL 2.
[21] D.23-04-040 at OP 1.

Similarly, ERDPs 5 and 6 provide that rates should encourage customer behaviors that improve electric system reliability, and optimize the use of existing grid infrastructure to reduce long-term electric system costs.[22] The Decision's cost allocation methodology limits the IOUs' ability to encourage such customer behavior by allocating TE program costs simply based on monthly usage, regardless of when that usage occurs during the 24-hour slice-of-day.[23] Modifying the Decision to allocate TE costs using the SAPC method would correct for this misalignment with the new principles by reducing the distortion to price signals in current and future time-variant rates.

B. The Commission's Recent Procurement Order Underscores the Need to Maintain Customer Responsiveness to Price Signals

On February 23, 2023, the Commission issued D.23-02-040 in the IRP Proceeding (R. 20-05-003), which ordered supplemental mid-term reliability procurement of 4,000 megawatts (MW) of net qualifying capacity for 2026-2027. Notably, that decision reflects new facts showing the difficulties in meeting growing electricity demand due to capacity constraints and project delays.[24] The supplemental procurement was required to address increases in forecast electricity demand, the increasing and accelerating impacts of climate change, and delays in long lead-time resource procurement ordered in D.21-06-035.[25]

The near-term reliability challenges reflected in D.23-02-040 underscore the need to maintain accurate price signals in existing rates. The Decision's equal cents per kWh cost

[22] *Id.*
[23] *See* D.23-04-010 in R.21-10-002 at OP 1, OP 23, and Appendix A. (The adopted 24-hour slice-of-day approach to resource adequacy addresses system reliability across every hour of the year.)
[24] D.23-02-040 at pp. 2, 6-7.
[25] *Id*.

allocation methodology threatens to worsen reliability challenges, by weakening existing price signals that encourage customers to shift usage to less capacity-constrained time periods. Accordingly, the new facts presented in D.23-02-040 support adoption of the proposed modification to allocate TE costs on a SAPC basis.

C. The IOUs Filed Advice Letters Required by the Decision Which Reveal that BTM TE Cost Allocation Will Fall Disproportionately on Large Industrial Customers

Ordering Paragraph 13 of the TE Decision required each of the IOUs to, within 30 days of the decision, "file a Tier 2 Advice Letter to update the rate and bill impacts associated with the authorized investments for the Funding Cycle 1 program, including the full revenue requirement associated with the approved program."[26] On December 21, 2022, PG&E filed Advice Letter 6796E, in which PG&E provided "illustrative rate impacts resulting from PG&E's illustrative share of the authorized revenue requirement" resulting from recovery of BTM TE costs through the distribution rate component on an equal-cents per kWh basis.[27] Table 2 of the PG&E Advice Letter revealed that under the TE Decision, PG&E's industrial customers would see a percent rate increase at least 50% higher than all customer classes except the standby customer class.[28] San Diego Gas & Electric Advice Letter 4128-E estimated that medium and large commercial and industrial customers (blended together into a single classification) would see a percent rate increase 24.24% higher than residential customers.[29] Southern California

[26] D.22-11-040 at p. 232.
[27] Advice Letter 6797-E "PG&E's Updated Rate and Bill Impacts, in Compliance with OP 13 of D.22-11-040" dated December 21, 2022.
[28] *Id*.
[29] Advice Letter 4128-E "Update on San Diego Gas & Electric Company's Transportation Electrification Rate and Bill Impacts in Compliance with Ordering Paragraph 13 of Decision 22-11-040" dated December 21, 2022.

Edison estimated large power customers would see a percent rate increase 20% higher than residential customers.[30]

The Advice Letters make clear that, despite the Decision's intent to make sure that "costs are distributed across all customer classes equitably,"[31] the selected allocation methodology requires large industrial users like the members of CLECA and EPUC to bear a disproportionate share of BTM TE costs. In light of the estimates provided by the IOUs in response to the Decision, the Decision should be modified to use the SAPC allocation methodology to "[smooth] out drastic rate impacts across customer classes"[32] and ensure that no particular customer class is required to bear a disproportionate share of BTM TE costs.

III. REQUESTED RELIEF AND SPECIFIC WORDING TO CARRY OUT THE REQUESTED MODIFICATIONS

For the foregoing reasons, Petitioners respectfully request that the Decision be modified to allocate TE program costs on a SAPC basis, rather than an equal cents per kWh basis. The specific proposed modifications are provided below.

The following wording changes should be made to the text at 51:

> We also require the IOUs to allocate FC1 program costs and all BTM TE program costs moving forward on ~~an equal cents per kWh~~ <u>*system average percent change (SAPC)*</u> basis<u>*, meaning that each rate component will be increased or scaled by the same percentage regardless of customer classification*</u>. This helps ensure that costs are distributed across all customer classes equitably <u>*by smoothing out volatility in class average rate changes while preserving price signals and improving rate stability during a transitional period*</u>. ~~Further, parties' comments described above do not account for the new EV Infrastructure Rules and, therefore, address both BTM and~~

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[30] Advice Letter 4925-E "Transportation Electrification Framework Funding Cycle 1 Rate and Bill Impacts Pursuant to Decision 22-11-040" dated December 21, 2022.

[31] D.22-11-040 at p. 51.

[32] D.21-01-017 at 43.

~~utility-side costs. As utility-side costs are not included in the program contemplated here, it is even more appropriate to adopt the equal cents per kWh approach.~~

The following wording changes should be made to Finding of Fact 10:

> ~~An equal cents per kWh~~ *A system average percent change (SAPC)* allocation factor will ensure that costs are distributed across all customer classes equitably *by smoothing out volatility in class average rate changes while preserving price signals and improving rate stability during a transitional period*.

The following wording changes should be made to Conclusion of Law 11:

> The Commission should require the IOUs to allocate FC1 program costs and all BTM TE program costs on ~~an equal cents per kWh~~ *a system average percent change (SAPC)* basis.

The following wording changes should be made to Ordering Paragraph 3:

> Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall record all behind-the-meter transportation electrification (TE) program costs in either a one-way subaccount within each IOU's TE Balancing Account or through a separate one-way balancing account. The IOUs shall record such costs as expenses, rather than capitalizing the costs. The IOUs shall recover such costs through distribution rates allocated on a ~~an equal cents per kilowatt hour basis applied equally~~ *system average percent change (SAPC) basis applied* to all customer classes.

IV. CONCLUSION

Petitioners appreciate the opportunity to petition for modification of D.22-11-040 and urge the Commission to grant this petition on an expedited basis.

Respectfully submitted,

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