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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rate	Application 24-03-019 (Filed March 29, 2024)

OPENING BRIEF OF THE
THE SOLAR ENERGY INDUSTRIES ASSOCIATION

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Pursuant to Rule 13.1of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the October 3, 2025 E-Mail Ruling of the Assigned Administrative Law Judge, the Solar Energy Industries Association ("SEIA") hereby submits its Opening Brief on the *Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rate*, filed in the above captioned proceeding on March 29, 2024.

I. INTRODUCTION

As a result of the diligent work of the parties to this proceeding, the vast majority of issues put before the Commission through Southern California Edison Company's ("SCE") application were settled, limiting the required briefing to three issues:

1. Whether the Commission should adopt SCE's proposed TOU-D PRIME Plus rate,
2. Whether the Commission should adopt The Utility Reform Network's proposal to increase the baseline allowance, and
3. Whether the Commission should adopt SEIA's proposal regarding transmission marginal capacity costs.

In this brief, SEIA will address the first and the third issues. Specifically, SEIA will illustrate that SCE's proposed TOU-D PRIME Plus rate is not just and reasonable and therefore should not be adopted by the Commission. In addition, SEIA will demonstrate that its recommended Marginal Transmission Capacity Cost ("MTCC") value of $73 per kW-year for SCE should be adopted.

II. THE COMMISSION SHOULD REJECT THE PROPOSED TOU-D PRIME PLUS RATE

SCE's proposed TOU-D PRIME Plus rate would be a version of SCE's PRIME rate with the following differences:

- A customer charge of $49 per month that recovers marginal customer costs and non-marginal distribution costs;[1]
- A seasonal time-related demand ("TRD") charge of $3.18 per kW in the summer and $2.62 per kW in the winter, with a customer's demand based on their highest 60-minute usage in a billing period; and
- A higher seasonal rate differential of $0.08 per kWh.[2]

The higher fixed charge will result in lower volumetric rates in all time-of-use ("TOU") periods, while the TRD Charge will lower on-and mid-peak volumetric TOU rates.

SCE is promoting its TOU-D PRIME Plus proposal as a cost-based, optional rate that promotes electrification. SEIA supports optional rates that are designed to meet specific customer needs not addressed by other rates. However, such rates should be (1) consistent with applicable law and prior Commission decisions regarding rate design components, (2) truly cost-based, and (3) demonstrated to be understood by the customers for whom they are intended. SCE's proposed TOU-D PRIME Plus lacks all of these features and as a result is not just and reasonable. The Commission must reject this proposed rate.

A. The Fixed Charge Component of PRIME Plus is Not Consistent with Applicable Law

SCE's proposed $49 per month fixed charge is comprised of the fixed costs approved by

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1 *See* Exhibit SCE-06, at pp. 22-25.

2 *See* Exhibit SCE-04, at pp. 68-70.

the Commission in Decision 24-05-028,[3] as well as non-marginal distribution costs.[4] Including non-marginal distribution costs in a fixed charge is not consistent with Public Utilities Code Section 739.9(d), as interpreted by the Commission.

Section 739.9(d) of the Public Utilities Code provides that the Commission "may adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of *the fixed costs* of providing electrical service to residential customers." This mandate limiting the type of costs that can be recovered through a residential fixed charge – i.e., fixed costs - is not restricted to fixed charges in default rates. It is applicable to all residential fixed charges.

The term "fixed costs" was not defined in the enabling legislation but left to the Commission. In making this assessment, the Commission found that:

> The intent of the Legislature was to address the recovery of fixed costs that do not "directly" vary based on how much a given customer uses. In other words, a fixed cost has a revenue requirement that does not vary based on the electricity usage of the customer from whom the revenue is being collected.[5]

Based on this definition of fixed costs, the Commission determined which costs collected by the IOUs are fixed and thus eligible to be recovered through a fixed charge. As part of its analysis the Commission examined the claim of the Large Utilities, including SCE, that "all Non-Marginal Distribution Costs are fixed,"[6] noting that the Large Utilities "generally described these costs as including many distribution costs that are not directly linked to marginal costs, including the costs of wildfire mitigation and vegetation management, reliability improvements,

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3 The fixed costs approved by the Commission for recovery through a fixed charge are: (1) marginal customer costs, (2) public purpose program costs, (3) new system generation and local generation charges, and (4) nuclear decommissioning non-bypassable charges. *See* Decision 24-05-028, pp. 64-72.

4 Exhibit SCE-06, p. 22, lines 7-9.

5 Decision 24-05-038, p. 22-23.

6 *Id.*, p.68.

safety and risk management distribution costs, ongoing distribution operations and maintenance, many regulatory balancing accounts, and various programs and policy mandates."[7] Importantly, in assessing the Large Utilities' claim, the Commission noted that "the Large Utilities did not include a list of all components of Non-Marginal Distribution Costs and justification for considering each component as a fixed cost in testimony."[8] As a result, the Commission concluded that "[t]he record is not sufficient to determine which portion of Non-Marginal Distribution Costs are fixed costs" thus "[w]e will not recover these costs through income-graduated fixed charges at this time."[9]

The Commission is facing the same situation here. SCE has proposed to include marginal distribution costs in its TOU-D PRIME Plus fixed charge.[10] It has not delineated specifically what those costs are or provided any justification in its testimony for why those costs should be considered fixed. The record is devoid of any information upon which the Commission could determine that the non-marginal distribution costs which SCE proposes to collect through the fixed charge in the TOU-D Prime Plus rate are fixed costs. Accordingly, SCE's proposed fixed charge must be rejected.

B. Demand Charge are not Necessary or Suitable for Residential Rates

1. The Demand Charge Component of PRIME Plus is Not Cost Based

Throughout its testimony on TOU-D PRIME Plus, SCE pushes the argument that it

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7 *Id.,* pp. 68-69.

8 *Id.,* p. 69.

9 *Id.*

10 Exhibit SCE-05, p. 23, lines 7-8. Notably, SCE filed supplemental testimony in this case that was supposed to conform its rate proposals to D. 24-05-028, but instead of conforming the TOU-D-PRIME-Plus fixed charge to the findings of that order, SCE doubled down on its proposal and raised the proposed TOU-D-PRIME-Plus fixed charge from $33 to $49, with the higher fixed charge now recovering not just a portion, but all of SCE's non-marginal distribution costs.

purportedly will recover revenue through “functional cost-based components,” resulting “in a rate structure that approaches the well-established three-part cost-based rate design that is the standard for non-residential rates.”[11] This argument fails to account for the differences between serving residential and non-residential loads.

Specifically, SCE proposes to use the demand charges in the TOU-D-PRIME-Plus rate to recover peak-related distribution costs.[12] Recovery of such costs from residential customers through a demand charge is not cost-based. The reality is that there is a substantial level of diversity on residential circuits with many small customers, even during the limited number of peak period hours. Therefore, the utility does not need to plan to size residential circuits to serve the sum of the noncoincident peak demands of all residential customers on the circuit.[13] This level of diversity does not exist on circuits serving larger non-residential customers. For non-residential loads, the noncoincident demands of a few large customers can constitute a significant part of a circuit’s peak demand. As a result, demand charges are more reasonably a part of the distribution rates for commercial and industrial customers.[14]

Moreover, if it truly is SCE’s intent to design a *residential* rate that reflects cost-based recovery of peak-related distribution costs, then other options are available, such as collecting such costs based on a customer’s average demand over a summer on-peak TOU period that covers the hours when the circuit on which the customer takes service is most likely to peak.[15]

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[11] Exhibit SCE-06, p. 5, lines 8-10; *id*, p. 7, lines 2-4.

[12] *See* Exhibit SEIA-01, p. 47 lines 17-18 *citing* SCE's "Residential Optional Rates Amended.xlsx" workpaper, the "TOU-D-PRIME Dmd" tab, at column BQ. The demand charges are based on 46.03% of the Distribution TRD costs shown in column X.

[13] Exhibit SEIA-01, p. 46, lines 18-21

[14] *Id.*, p. 46, lines 21-23.

[15] *Id.,* p. 46, lines 25-27.

This can be accomplished through a volumetric TOU charge to recover such costs during these peak hours. A customer's kWh usage over the peak period measures the customer's contribution to the average demand during those high-load hours. Given the diversity of residential loads, this is a reasonable measure of a customer's contribution to peak demand, and is the basis for a reasonable, cost-based charge.[16]

2. Demand Charges do Not Necessarily Enhance Customer Response

SCE asserts that the additional on-peak demand signal creates an extra level of awareness and thus will create an even greater response as opposed to simply increasing the on-peak volumetric rate.[17] SEIA disagrees with this argument and submits that the opposite is more likely true. SCE's proposed demand charge does make a customer's maximum 60-minute usage every month highly consequential for the customer's bill. However, it also removes much of the incentive for the customers to use less than this maximum in any other 60-minute period. For example, if the residential customer of record is momentarily inattentive, and a member of their household mistakenly charges the EV for a single on-peak hour, there will be no further incentive from the demand charge to limit on-peak demand to below this level for the remaining days of the billing period.[18] The result is likely to be less demand response, and a frustrated customer with a high bill. In contrast, an on-peak volumetric TOU rate sends the customer a consistent signal to minimize their on-peak usage in every on-peak hour, and rewards customers who use as little power as possible during all on-peak hours, without being punitive if a customer happens

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16 *Id.,* p. 47, lines 1-3. Another option would a Critical Peak Pricing rates, which are volumetric TOU rates that charge very high on-peak rates to customers in a limited number of high-demand hours each year that the utility or system operator declare on a day-ahead basis. *Id.*, p. 47, lines 3-6.

17 Exhibit SCE-06, p. 11, lines 5-7.

18 Exhibit SEIA-01, p. 43, line 21 to p.44, line 3; *see also* p. 45, lines 1-3 and p. 52, line 25 to p.53, line 15.

not always to bring that "extra level of awareness" to their energy usage. Volumetric TOU rates can be further improved by overlays such as critical peak pricing, which focuses a typical customer's limited attention to their energy use to those days and hours that are most important.

3. SCE Has Not Demonstrated Sufficient Customer Understanding of the Demand Charge Component of its PRIME Plus Proposal

Residential customers in California have never been exposed to a demand charge.[19] Thus, while residential consumers have experience with their energy use, in kilowatt-hours (because that is the basis on which they have been billed), they do not have experience with the concept of demand, measured in kW, which is the rate at which a customer uses energy as a function of time.[20] Even for those customers that understand the difference between kWh of energy and kW of demand, they do not have readily available data on the kW power demand that their household appliances consume in order to make intelligent decisions to reduce their maximum kW demand.[21] This current dynamic could lead to a high degree of customer confusion with the introduction of a residential demand charge.

SCE shrugs off this reality, "respectfully recommend[ing] that the Commission not hesitate in adopting a highly cost-based rate option based on speculative arguments regarding customer confusion" as "[c]ustomers are savvier than SEIA gives them credit for."[22] Thus, SCE asserts that "with proper education and outreach, rate structures that introduce new features can ultimately be understood." [23]

This is not an issue of SEIA assessing customers' savviness. SEIA agrees that with proper

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19 Exhibit SEIA-01, p. 42, lines 2-3.

20 *Id.,* p. 42, lines 4-8.

21 *Id.*, p. 42, lines 12-18.

22 Exhibit SCE-06, p. 13, lines 5-7.

23 *Id.*, p. 13, lines 12-13.

education and access to applicable data, customers can ultimately understand changes in a rate structure such that, at times, they can respond accordingly. But SCE has not provided any showing of an education and outreach plan to facilitate such understanding. Indeed, SCE's direct and supplemental testimony on its TOU-D PRIME Plus proposal made no mention of the need for such customer outreach. On rebuttal, SCE asserts that it has been "proactively conducting research to evaluate naming options for the new rate as well as how customers understand various rate components, such as the demand charge."[24] As evidence of such "research" SCE provides what they call a "PRIME Rate Plus Naming Study" which is comprised of two pages -- the first which shows the results of a survey regarding what the demand charge should be called, and the second containing a handful of customer quotes selected by SCE addressing the survey respondents' understanding of demand charges.[25] This "Naming Study" does not constitute a showing that SCE has conducted adequate education and outreach or that there is an suitable level of customer understanding of demand charges among residential customers, even those who would self-select to take service under TOU-D PRIME Plus.

III. THE COMMISSION SHOULD ADOPT SEIA'S RECOMMEND MARGINAL TRANSMISSION CAPACITY COSTS

The Commission should approve the SEIA's recommended Marginal Transmission Capacity Costs ("MTCCs") which were derived using a Commission-approved methodology. Despite the fact that SCE's transmission rates are under the jurisdiction of the Federal Energy Regulatory Commission, approval of MTCCs for SCE is warranted. As discussed below, the IOUs' MTCCs are increasingly being utilized for a variety of rate design purposes. A GRC Phase 2 case, in which all of the IOU's other marginal costs are reviewed and potentially litigated, is

[24] *Id.*, p. 13, lines 17-19.

[25] *Id.,* Appendix C.

the obvious forum to afford parties the opportunity to review, and to litigate if necessary, an IOU's marginal transmission capacity costs. Such occurred in Pacific Gas and Electric Company's ("PG&E") 2020 GRC Phase 2 proceeding in which PG&E's marginal transmission capacity costs were litigated. The result was that the Commission adopted SEIA's proposed MTCC for PG&E.[26] Based on that precedent, SEIA's submission of a detailed proposal for SCE's MTCC in this Phase 2 case was reasonable and constructive and deserves careful review by the Commission.

A. An Accurate Assessment of SCE's MTCCs is Warranted

The Commission's increasing use of marginal transmission capacity costs in ratemaking warrants adoption of MTCCs for SCE. For example, the Commission is using the IOUs' marginal transmission capacity costs directly in the export rates for new solar and storage customers under the Net Billing Tariff ("NBT").[27] For PG&E these are the marginal transmission capacity costs which were adopted in Decision 21-11-016, as discussed above. SCE and San Diego Gas & Electric Company ("SDG&E"), not having comparably vetted MTCCs from their Phase 2 cases, have been directed to calculate those MTCCs using the methodology approved for PG&E.[28] But whether SCE and SDG&E are in fact doing so, and whether the data these IOUs are employing is accurate and up to date has not been made the subject of litigation, thus leaving parties, and the Commission, with an incomplete picture of these IOUs' MTCCs.[29] Next year the Commission will once again embark on the proceeding to update the NBT export

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26 *See* D. 21-11-016, pp. 65-70.

27 *See* D. 20-04-010, pp. 60-62, (for the 2020 ACC) adopted the use of PG&E's method used to calculate marginal transmission costs in its GRC Phase 2 cases. D. 22-05-022, pp. 73-75 (for the 2022 ACC), and D. 24-08-007, p. 38 (for the 2024 ACC) continued the use of this approach.

28 *See* D. 20-04-010, p. 60; D. 22-05-002, pp. 73-75; and D. 24-08-007, p. 38.

29 *See, in general,* Exhibit SEIA-01, p 20, line 3 to p.21 , line 3.

rates for each of the IOUs (*i.e.*, the Avoided Cost Calculator update). Using a MTCC for SCE that was adopted in this proceeding will enhance the accuracy of that review.

Second, marginal transmission capacity costs will be necessary to derive an accurate transmission component of the dynamic rates that are under development pursuant to R. 22-07-005. Indeed, the Demand Flexibility Design Principles adopted by the Commission recognize accurate marginal costs, including transmission, as essential building blocks of dynamic rates.[30] SCE filed an application for approval of dynamic rates on December 20, 2024, which was supplemented on October 28, 2025 in accordance with Decision 25-08-049. In its supplemental filing, SCE did not establish a MTCC for its proposed dynamic rates. Rather it stated that "the process for adopting MTCC will align with SCE's [CEC] approved LMS Compliance Plan, which states that SCE intends to file a Single-Issue 205 application with FERC following CPUC approval of its transmission rate framework."[31] Thus, while the FERC ultimately has jurisdiction over SCE's transmission rates, SCE indicates that the Commission should approve a "transmission rate framework" which of necessity would include MTCCs. Clearly, approval of a MTCC for SCE in this case will achieve that goal in a timely way, without the need for further Commission proceedings.

Finally, having an accurate assessment of SCE's MTCCs could be useful in other Commission forums as it moves to encourage electrification. For example, commercial electric vehicle ("EV") rates for PG&E and SDG&E have been structured to reduce distribution costs to marginal costs, to allow these rates to compete with liquid fuels, to provide headroom to recover

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30 *See* Decision 23-04-040, p. 3 (Principle 3: Dynamic prices should, to the extent feasible, accurately incorporate the marginal costs of energy, generation capacity, distribution capacity, and transmission capacity based on grid conditions; Principle 6: Demand flexibility tariffs should provide marginal cost-based compensation for exports to enable economically efficient grid integration of customer-sited electrification technologies and distributed energy resources).

31 Application A.24-06-014, Exhibit SCE-04, p. 14.

the incremental costs of serving this major new load, and to calculate contributions to margin in assessing the performance of these rates. Commercial EV rates that reduce transmission rates to marginal costs would provide additional encouragement to the deployment of needed EV charging infrastructure. Economic development rates have a similar structure and also require marginal costs to calculate contributions to margin. The Commission should assure that it has access to accurate accountings of all of the IOUs' marginal costs as it increasingly moves toward the adoption of rate structures designed to incent electrification.

B. The Record Supports a $73 per kW-year MTCC for SCE

The record of this proceeding contains only SEIA's derivation of MTCCs. SCE did not offer a calculation of its MTCCs; either on direct or rebuttal. As illustrated below, the MTCCs advanced by SEIA - $73 per kW-year – were calculated in accordance with the Commission-approved methodology and thus should be adopted.

Specifically, SEIA calculated SCE's MTCCs using the Discounted Total Investment Method ("DTIM") developed by PG&E to calculate its marginal transmission costs. As referenced above, this approach was approved by the Commission in D. 20-04-010 for use by SCE and SDG&E in calculating marginal transmission costs for use in the ACC. Accordingly, in order to perform this calculation, SEIA started with the DTIM calculation methodology for SCE used for the 2024 ACC, but updated the data used to include the costs of the SCE reliability-related transmission projects approved by the CAISO in May 2024 for its 2023-2024 Transmission Plan. In this regard, it is critical to note that, given a purported time constraint, the Commission excluded the data from the 2023- 2024 CAISO Transmission Plan it is calculation of SCE's MTCCs used in the 2024 ACC, despite recognizing the benefits of including that up-to-date data. Specifically, in the Resolution adopting the 2024 ACC, when discussing SEIA's recommendation that avoided transmission costs in the 2024 ACC should include all reliability-related transmission projects included in the 2023-24 CAISO Transmission Plan, the Commission stated that:

> While the Energy Division recognizes the benefit generally of using the most recent data available, given the time constraints for approval of the 2024 ACC, it is not feasible for the avoided transmission costs to be revised at this time….[32]

The result of SEIA's calculation of SCE's MTCCs – applying the DTIM calculation methodology and "using the most recent data available" – is a marginal transmission capacity cost of $73 per kW-year.[33]

SEIA validated this result by using a different approach – applying the standard NERA regression methodology to SCE's historical and forecasted CAISO transmission costs. SCE has long used the NERA method to calculate its avoided distribution capacity costs.[34] SEIA was able to apply the NERA regression method in this case to determine SCE's MTCC by updating SCE's FERC Form 1 CAISO transmission cost data and using data from recent CAISO transmission plans to exclude from the calculation SCE's "policy-related" RPS transmission costs whose primary purpose is to access new renewable generation.[35] The result was a MTCC value of $75 per kW-year. The similar value from the NERA regression method helps to confirm the reasonableness of the $73 per kW-year derived by applying the DTIM.[36]

IV. CONCLUSION

For the reasons stated above, SEIA respectfully requests that the Commission:

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32 Resolution E-5328, p. 11.

33 Exhibit SEIA-01, p. 22, lines 16-21.

34 *Id.*, p. 22, lines 22-26.

35 *Id.,* p. 23, line 3-6.

36 *Id.*, line 7.

- Reject SCE's TOU-D PRIME Plus rate proposal; and
- Adopt a $73 per kW-year MTCC for SCE, as proposed by SEIA in this proceeding.

Respectfully submitted the 3rd day of November 2025 at San Francisco, California

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