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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 Rates.	A.20-10-012 (Filed October 23, 2020)

JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND SETTLING PARTIES FOR ADOPTION OF MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

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Dated: **December 13, 2021**

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I.

INTRODUCTION

Pursuant to Rule 12.1 *et seq*. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), in Application (A.) 20-10-012, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, Southern California Edison Company (SCE), on behalf of itself and the Settling Parties,[1] files this motion (Motion) that requests the Commission adopt the "Marginal Cost and Revenue Allocation Settlement Agreement" (Settlement Agreement or Agreement), which is appended to this Motion as Attachment A.

[1] The Settling Parties or Parties are: SCE; The Utility Reform Network (TURN); the Public Advocates Office at the CPUC (Cal Advocates); Small Business Utility Advocates (SBUA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); California City-County Street Light Association (CALSLA); Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); and Direct Access Customer Coalition (DACC). Pursuant to Rule 1.8(d), SCE has been authorized to file this motion on behalf of the Settling Parties. The following parties take no position on the Settlement Agreement: the Solar Energy Industries Association (SEIA); Enel X North America, Inc. (Enel X); EVGo Services, LLC (EVGo); Tesla, Inc.; Center for Accessible Technology (CforAT); California Choice Energy Authority (CCEA); the California Solar & Storage Association (CALSSA); and the Western Manufactured Housing Communities Association (WMA).

The Settling Parties have executed a Settlement Agreement that resolves all issues that have been raised with respect to revenue allocation and applicable marginal costs[2] in this proceeding. For purposes of determining the revenue allocation for settlement purposes, the Parties agreed to a set of marginal cost inputs that fell within the proposals made by the Parties in their direct testimony, which were then moderated by agreed-upon "collaring" and "capping" parameters. Accordingly, at a high level, the resulting settlement embodies a compromise and balance between the Commission's rate design principles of cost-causation and gradualism/rate stability. Pursuant to the terms of the Settlement Agreement, and as soon as practicable following a Commission decision adopting the Settlement Agreement, but no earlier than June 1, 2022, SCE will adjust its rates for all of its bundled service, Direct Access (DA), Community Aggregator (CA), and Community Choice Aggregation (CCA) customers consistent with the terms of the Settlement Agreement.

Section II of this Motion provides the background related to this proceeding. Section III describes in general the positions advocated by the Parties and the terms of the Settlement Agreement. Section IV demonstrates that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest, and that it should be adopted without modification. Section V discusses the procedural requests of the Settling Parties for disposing of this Motion and implementing revised rates.

II.

BACKGROUND

This proceeding was initiated by the filing of SCE's application on October 23, 2020, A.20-10-012, along with service of SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design. On December 22, 2020, SCE served supplemental testimony regarding certain revenue allocation proposals. On January 20, 2021, the Assigned Commissioner and Assigned Administrative

[2] "Applicable marginal costs" refers to the adoption of marginal costs solely for the purpose of establishing a revenue allocation, and not for any other purposes. The Settlement Agreement does not reflect the general acceptance of any of the Parties marginal costs proposals. See section III.A of the Settlement for more details.

Law Judge issued a Scoping Memo and Ruling following a December 16, 2020 prehearing conference. Cal Advocates served its direct testimony on June 24, 2021 and served amended testimony on July 8, 2021 and on August 11, 2021. On July 26, 2021, the following Settling Parties submitted prepared testimony regarding marginal cost or revenue allocation: TURN, SBUA, CFBF, AECA, CALSLA, DACC, CLECA, EPUC and FEA. Cal Advocates served supplemental testimony on revenue allocation, including rate collaring, on September 22, 2021.

SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on August 12, 2021. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference.

The Settling Parties represent a broad spectrum of customer interests, as indicated in Paragraph 1 of the Settlement Agreement. Each Settling Party represents customers or groups of customers who are directly affected by, and have an interest in, the resolution of the marginal cost and revenue allocation issues in this proceeding.

III.

SUMMARY OF POSITIONS AND SETTLEMENT

The Settlement Agreement resolves all issues related to revenue allocation and applicable marginal costs in this proceeding. Its primary provisions are summarized below and in a comparison exhibit, Appendix A to the Settlement Agreement, which provides a comparison of party positions related to the relevant issues and the manner in which these issues have been resolved by the Settlement Agreement.[3]

The major marginal cost and revenue allocation issues addressed in testimony include the following:

- Marginal customer, distribution demand, generation capacity, and generation energy cost components;

[3] Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

- Allocation of functional distribution and generation unbundled revenue requirements based on marginal cost components or in accord with prior Commission decisions;
    - This includes allocation of revenue requirements, generally, as well as allocation of specific categories of revenue requirements associated with specific costs, such as certain categories of wildfire-related costs or transportation electrification costs.
- Capping (or "collaring" as defined in the Settlement) of allocated revenues to rate groups to promote rate stability while achieving movement towards cost-based rate levels.

The Settlement Agreement resolves all issues raised in this proceeding with respect to revenue allocation and applicable marginal costs. Among other things, the Settlement Agreement provides the means of establishing average rates by rate group and schedule when this Agreement is first implemented and for the term of the Agreement. Illustrative average rates for each rate group based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement.

A. Marginal Costs

A number of issues were raised regarding the calculations and methodologies used to derive marginal customer costs, marginal generation capacity costs, marginal energy costs, and marginal distribution demand costs. The Settling Parties were able to reach agreement on the allocation of SCE's total revenue requirement among the rate groups, thereby obviating the need to litigate and resolve the differences regarding proposed marginal cost methodologies and forecasts.

The Settlement Agreement does not reflect the approval of, or acceptance of, any of the Settling Parties' marginal cost proposals. However, the Settling Parties agree that the marginal costs that were used to create the revenue allocation settlement set forth in Paragraph 4.A of the Settlement Agreement may be used for the purpose of initially establishing unit marginal costs that are used in SCE's revenue allocation and rate design model.

B. Revenue Allocation

Several parties raised a number of issues regarding the allocation to rate groups of SCE's Commission-authorized distribution and generation revenue requirements. Some Settling Parties proposed that the Commission should cap or limit the amount of SCE's revenue requirement that is allocated to any rate group, including different proposed caps and different proposed structures of caps (such as whether separate caps should apply to distribution and generation revenue requirements). Some Settling Parties raised other issues with respect to marginal costs, including the potential split of marginal generation capacity costs between "ramp" and "peak" functions and marginal distribution capacity costs between "peak" and "grid" functions.

In order to avoid litigation and to mitigate potentially adverse impacts on any particular rate group based on directional movement towards cost-based rates in this proceeding, the Settling Parties agreed on how to allocate SCE's total revenue requirement on an overall revenue-neutral basis, based on a number of assumptions to which the Settling Parties agreed (that are reflected in the settlement version of SCE's Revenue Allocation Model). While no change to SCE's total system revenue requirement is requested in this proceeding, the Settling Parties agreed to establish a method to allocate revenues to each rate group based on agreed-upon marginal costs (that are strictly non-precedential and were developed solely for the purposes of allocating revenues pursuant to the Settlement Agreement), methods of allocating revenues to each rate group, and a method for addressing future revenue requirement changes. Because the level of SCE's authorized revenues and sales at the time the Settlement Agreement will first be implemented are presently unknown, the Settlement Agreement reflects the use of a consolidated authorized SCE revenue requirement of $14,388 million as of October 1, 2021, which includes revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the Self-Generation Incentive Program (SGIP), Demand Response, the Wildfire Fund Non-bypassable Charge, Fixed Recovery Non-bypassable Charge, the New System Generation Charge (NSGC), and the GHG offsets.[4] The illustrative rate levels provided in Appendix B of this Agreement are based on this consolidated SCE revenue requirement and will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of this Agreement when rates are implemented pursuant to the provisions of this Agreement.

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[4] California Climate Credit and the revenues to be returned to EITE customers are included in the consolidated SCE revenue requirement of $14,388 million but are excluded during the revenue allocation and collaring process.

The Settlement Agreement produces changes in average rates for bundled service and DA, CA, and CCA (the latter three are collectively, "departing load customers") customer rate groups based on the consolidated revenue requirement, resulting in a bundled service system average rate level of 22.07¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's forecasted sales for 2021, as illustrated in Table B-1 of the Settlement Agreement (and reproduced below).[5] To promote rate stability, the revenue allocations and illustrative average rates agreed to by the Settling Parties employ restrictions on delivery and generation revenue changes both above and below the functional system average percentage change (SAPC), as detailed in Table RA-7 and Paragraph 4.B.2 of the Settlement Agreement (*i.e.*, "collaring").[6]

In order to produce functional rates for rate design purposes and to provide a basis for other revenue requirement changes occurring after this proceeding and before SCE's next revenue allocation proceeding, the Settling Parties agree that SCE's authorized revenue requirements (*i.e.*, the revenue requirements for transmission, distribution, SCE generation, Wildfire Fund Non-bypassable Charge, Fixed Recovery Non-bypassable Charge, departing load cost responsibility surcharge, nuclear decommissioning, public purpose programs, etc.) shall be allocated to rate groups as specified in the Settlement Agreement in Paragraph 4.B.5, subparts a through k.

Finally, the Settling Parties agree that distribution and generation revenue requirement changes occurring after the Commission has issued a decision in this proceeding and until Phase 2 of SCE's next general rate case (GRC) proceeding is implemented shall be allocated pursuant to the functional character of the revenue requirement change on an SAPC basis.

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5 Average rate changes for departing load customers are included in Table B-2 of Appendix B to the Settlement Agreement.

6 As explained in further detail in Section IV.A.7, below, the "WRR Incremental Revenue" amount of Wildfire-related revenue requirements will not be subject to the overall revenue allocation collaring.

IV.

REQUEST FOR ADOPTION OF THE SETTLEMENT

The Settlement Agreement is submitted pursuant to Rule 12.1 *et seq*. of the Commission's Rules of Practice and Procedure. The Settlement Agreement is also consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.[7] This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing the Parties to reduce the risk that litigation will produce unacceptable results.[8] As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest, it should be adopted without change.

The Settlement Agreement complies with Commission guidelines and relevant precedent for settlements. The general criteria for Commission approval of settlements are stated in Rule 12.1(d) as follows:

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.[9]

The Settlement Agreement meets the criteria for a settlement pursuant to Rule 12.1(d), as discussed below.

A. **The Settlement Agreement is Reasonable In Light Of the Record**

The prepared testimony, the Settlement Agreement itself, and this motion contain the information necessary for the Commission to find the Settlement Agreement reasonable in light of the record. Prior to the settlement, parties conducted extensive discovery and served testimony on the issues related to marginal costs and revenue allocation. In a separate motion, the Settling Parties will request that the Commission admit the prepared testimony and related exhibits into the Commission's record of this proceeding.

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[7] *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).
[8] D.92-12-019, 46 CPUC 2d 538, 553.
[9] *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360.

The Settlement Agreement represents a reasonable compromise of the Settling Parties' positions. The prepared testimony of the Settling Parties as well as Exhibit A to the Settlement Agreement (*i.e.*, the comparison exhibit) contain sufficient information for the Commission to judge the reasonableness of the Settlement. In summary, the Settlement Agreement is a reasonable resolution, and represents compromises within the range of Parties' various litigation positions, on the following subject areas:

1. Generation Capacity Marginal Costs (GCMCs)

The Parties advocated for different values of marginal generation capacity. Ultimately, the Settling Parties compromised on a GCMC value at $100/kW-year, for purposes of revenue allocation settlement. In addition, various parties initially had different proposals for allocating the proportion of MGCCs between "peak" and "flex" functions (as those terms are defined in the Settlement Agreement). Ultimately, the Parties agreed to use SCE's Capacity Allocation Tool to spread the GCMC across TOU periods and that it be partly allocated based on peak demand and partly based on the need for ramping capacity, *i.e.*, flexible capacity.

2. Generation Marginal Energy Costs (MECs)

The Settling Parties advocated for different values of generation marginal energy costs (MECs). For the purposes of this revenue allocation settlement, the Parties agreed to a set of marginal energy costs that are based on an average forecasted total fuel cost of $5.65/MMBtu ($1.42/MMBtu GHG-related costs based on the Cap-and-Trade Program and $4.23/MMBtu based on SoCal Citygate gas price) in addition to a Renewables Portfolio Standard (RPS) adder forecast for the year 2024.

3. Customer Marginal Costs Methods

Various Parties, including SCE, Cal Advocates and TURN, advocated for different customer-specific marginal costs, based on different methodologies. For purposes of revenue allocation, the Settling Parties agreed on marginal customer costs that were determined based on a 50:50 ratio of SCE's Real Economic Carrying Charge (RECC) and TURN's New Customer Only (NCO) marginal customer costs calculations.

4. **Distribution Design Demand Marginal Costs (DDMCs)**

The Parties advocated for different values of distribution design demand capacity. Ultimately, the Settling Parties agreed to adopt SCE's proposed DDMC value for the purposes of revenue allocation. SCE and interested parties have agreed to engage in discussions to explore derivation of design demand marginal cost and refinement to the peak/grid split for incorporation in SCE's next GRC Phase 2 proceeding.

5. **Sales Forecast**

The sales forecast embodied in the Settlement Agreement results from SCE's 2021 ERRA application (and supporting direct testimony therefrom), which represents SCE's then-current estimate of departing load for 2021.

6. **"Capping"/"Collaring"**

SCE did not initially propose to "cap" or impose "collars" on any rate changes resulting from this proceeding. Various other parties proposed rate collars, however, at various percentage levels, and for different rates. Ultimately, the Settling Parties agreed to use collars of plus and minus 2.0 percent and 1.5 percent for delivery and generation services, respectively, for the purposes of revenue allocation. These percentages fall within the range of party proposals. This outcome promotes rate stability for customers.

7. **Wildfire-Related Revenue Requirement**

Various Parties advocated for a specific allocation protocol to be applied to costs associated with certain categories of wildfire-related revenue requirements. Ultimately, the Settling Parties compromised on an allocation formula that would be applied to the following categories of existing and future Commission-authorized wildfire-related revenue requirements (WRR):

(1) Wildfire-related costs authorized in GRC base rates,[10] including but not limited to, costs tracked in the following accounts: Wildfire Risk Mitigation Balancing Account;[11] Vegetation Management Balancing Account;[12] and Risk Management Balancing Account;[13]

(2) Wildfire-related costs authorized in proceedings other than the GRC that review the reasonableness of the following accounts: Catastrophic Event Memorandum Account;[14] Wildfire Expense Memorandum Account;[15] Wildfire Mitigation Plan Memorandum Account;[16] Fire Risk Mitigation Memorandum Account;[17] and other Commission-authorized balancing and memorandum accounts that may be established that include wildfire-related costs;

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[10] Wildfire-related costs authorized in the GRC include, but are not limited to, those costs identified in Section 17 of D.21-08-036. Such costs include, for example, capital expenditures for wildfire risk mitigation and wildfire-related O&M. "Capital expenditures for wildfire risk mitigation" refers to those utility distribution capital costs subject to Section 8386(e) of the Public Utilities Code, as well as other utility distribution infrastructure costs related to fire risk mitigation. "Wildfire-related O&M" refers to O&M expenses related to catastrophic wildfires.

[11] The two-way Wildfire Risk Mitigation Balancing Account (WRMBA) records the difference between the Wildfire Covered Conductor Program (WCCP) capital expenditures authorized in Track 1 of SCE's 2021 GRC Decision (D.) 21-08-036 and SCE's recorded (actual) WCCP capital expenditures. The capital-related revenue requirements for actual WCCP expenditures in excess of a 110 percent reasonableness threshold are subject to additional reasonableness review prior to recovery from customers.

[12] The two-way Vegetation Management Balancing Account (VMBA) records the difference between authorized O&M expenses adopted in D.21-08-036 for vegetation management activities and actual O&M expenses for vegetation management activities. Actual O&M expenses that exceed 115 percent of the authorized amount are subject to additional reasonableness review prior to recovery from customers. Wildfire-related costs tracked in the VMBA include, for example, wildfire vegetation management through SCE's Hazard Tree Management Program, and dead, dying and diseased tree removal.

[13] The one-way Risk Management Balancing Account (RMBA) records the difference between actual insurance premium expenses for wildfire liability coverage, including the costs of alternative risk transfer instruments, and the authorized insurance premium expenses for wildfire liability coverage adopted in D.21-08-036.

[14] The Catastrophic Event Memorandum Account (CEMA) includes, in pertinent part, incremental capital expenditures and O&M for restoration and/or repair of SCE's facilities as a result of a wildfire that is declared a disaster by a competent state or federal authority.

[15] The Wildfire Expense Memorandum Account (WEMA) includes, for example, wildfire liability claims payments, litigation costs and associated financing costs (in excess of amounts covered by insurance, and net of third-party credits), as well as payments made for liability and property wildfire insurance.

[16] The Wildfire Mitigation Plan Memorandum Account (WMPMA) includes, for example, incremental costs incurred to implement SCE's Wildfire Mitigation Plan (WMP) that are not otherwise covered in SCE's revenue requirements or tracked in another ratemaking account.

[17] The Fire Risk Mitigation Memorandum Account (FRMMA) includes, for example, incremental costs incurred for fire risk mitigation that are not otherwise covered in SCE's revenue requirements or recorded in another memorandum accounts such as the WMPMA or the CEMA.

(3) Wildfire-related costs that are authorized to be recovered through a Fixed Recovery Non-bypassable Charge.[18]

The Settling Parties agree that the above-described WRR shall be recovered through distribution rates. The Settling Parties agree the allocation of WRR shall be as follows:

- Capped Revenue Allocation: The revenues for up to the first $525 million ("WRR Capped Amount") will be allocated using a 50 percent / 50 percent average of the distribution allocator and system average percent (SAP) allocator, respectively;
    - The annual WRR cap of $525 million will remain fixed until the next GRC Phase 2 is resolved.

- Incremental Revenue Allocation: The "WRR Incremental Revenue" is all amounts of WRR that exceeds the $525 million and will be allocated using a 12.5 percent / 87.5 percent average of the distribution allocator and SAP allocator, respectively.

The revenues for the first $525 million (*i.e.*, the WRR Capped Revenue) will be allocated among the functional revenues before any rate collaring is applied to the overall changes to revenue allocation. The revenues in excess of $525 million (*i.e.*, the WRR Incremental Revenue) will be added to the model after the overall revenue allocation collaring is performed and are not subject to the collaring process.

The capped and incremental revenue allocations will be combined to develop a composite weighted average allocator ("Special Allocator") that combines the distribution and SAP weights multiplied by the respective class allocators:

$$\text{Special Allocator}_i = (\text{Distribution Weight*Distribution Allocator}_i) + (\text{SAP Weight*SAP Allocator}_i)$$ [19]

Below is an example intended only to provide an illustration of how the Special Allocator is developed:

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[18] "Fixed Recovery Non-bypassable Charge" refers to a charge imposed on customers to pay the Recovery Bond principal, interest, and other related costs issued under Public Utilities Code § 850.1.

[19] Subscript "*i*" in the formula denotes the allocator assigned to each rate class.

1. Starting with a total annual WRR of $898 million as of October 2021, $525 million is the WRR Capped Amount and $373 million is the WRR Incremental Amount.

2. The WRR Capped Amount of $525 million is allocated by class:
   $525 million ((50% * Distr. Allocator$_i$) + (50% * SAP Allocator$_i$))

3. The WRR Incremental Amount of $373 million is allocated by class:
   $373 million ((12.5% * Distr. Allocator$_i$) + (87.5% * SAP Allocator$_i$))

4. The Special Allocator (%) for each customer class is the sum of the WRR Capped Amount and the WRR Incremental Amount for that class divided by the total WWR.

Once the Special Allocator is established for each class, it will also be used to allocate any additional WRR authorized for rate recovery during the year until the next annual adjustment. The Special Allocator will be adjusted annually during the attrition years, concurrent with the annual sales forecast adjustment, to account for the then-current amount of the total annual WRR. The average distribution and SAP allocators will be updated annually to reflect changes to the billing determinants (sales), each class's percentage share of total system revenues, and the Distribution and SAP weights. These updates will be inputted using the formulas above to derive the Special Allocator that will be used during each year.

Wildfire-related revenue requirements that are subject to Recovery Bonds that are recovered through a Fixed Recovery Non-bypassable Charge are considered part of the overall WRR that is considered during the development of the Special Allocator. To retain the Special Allocator computed from the WRR allocation formula while also retaining the revenue allocation established for a securitized amount pursuant to its applicable Commission Financing Order,[20] SCE shall establish each customer class's allocation of the non-securitized portion of the WRR such that the total weighted allocation for that class (*i.e.*, the securitized allocation and the non-securitized allocation) conforms to the Special Allocator.

For future wildfire-related securitizations, the Special Allocator shall be used to establish the allocation of the securitized amount. The Special Allocator effective at the time SCE files a request

[20] The existing revenue allocation associated with wildfire-related securitization adopted in D.20-11-207 and D.21-10-025 shall be retained and unaffected by the Special Allocator.

for authorization to issue Recovery Bonds will be used to establish a fixed allocation factor for the life of the bond, with adjustment for sales changes as necessary to ensure collection of the necessary Commission-authorized revenue requirement.

8. Transportation Electrification Allocation

Various Parties, including SCE and Cal Advocates, advocated for a specific allocation protocol to be applied to costs associated with transportation electrification (TE) programs. The Settling Parties agree that the allocation and recovery of revenue requirements associated with the following four TE programs will maintain the allocation and recovery methods directed in each program's respective Commission decision: Charge Ready Phase 1 Pilot; Charge Ready School and Parks; Charge Ready 2; and Transportation Electrification authorized in D.18-01-024 and D.18-05-040.

Settling Parties agree the above-described TE allocation and recovery methodologies do not apply to future TE programs that SCE may propose. Any such future TE program application will be subject to the cost allocation authorization made in the proceeding that authorizes the program and associated funding.

9. Other Issues

SCE will initiate a working group with interested parties to discuss best practice and methodologies in the determination of Design Demand Marginal Costs (DDMC) for the purposes of revenue allocation and rate design. In particular, the working group will seek to understand cost factors such as load, installed capacity, distribution investment, and line miles used when defining design demand marginal costs, the peak/grid split, and the allocation of such costs to customer classes. Participants in the working group process will be encouraged to propose the kinds of data that SCE should collect. These data could be used for parties' testimony in SCE's 2025 GRC Phase 2 and for the study described in this section. In the interim, if the desired data are not yet available, the Parties should discuss methodologies to accommodate that gap or availability of alternative data. In testimony, Cal Advocates and SBUA have proposed alternative methodologies that can be explored by Parties.[21]

TURN has suggested that the working group include a review of megawatt measures used in the DDMC analysis. TURN's analysis recognizes the difference in measures of MWs (installed capacity) that are used in SCE's DDMC regression analysis to calculate the marginal delivery costs, and the measure of MWs (consumer group hourly load) used to allocate marginal delivery costs to classes.[22] The working group will identify methodologies, including the use of "scalars" as advocated in TURN's testimony or other solutions, to ensure that the model captures and appropriately applies all costs for the purposes of revenue allocation and rate design. Other stakeholders, such as PG&E, SDG&E, and the Commission's Energy Division, will be invited to participate in these discussions. Upon conclusion of the working group's efforts, which may result in a workshop, SCE shall perform one or more studies, the results of which shall be served on the Settling Parties when SCE files its 2025 GRC Phase 2 Application (and serves its supporting testimony), that will explore the determination of DDMC, and which may be used for proposing refinements to SCE's current approach for cost determination and revenue allocation.

B. <u>The Settlement Agreement is Consistent with the Law</u>

The Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes and prior Commission decisions, and reasonable interpretations thereof. In agreeing to the terms of the Settlement Agreement, the Settling Parties have considered the relevant statutes and Commission decisions and believe that the Commission can approve the Settlement Agreement without violating applicable statutes or prior Commission decisions.

C. <u>The Settlement Agreement Is In the Public Interest</u>

The Settlement Agreement is a reasonable compromise of the Settling Parties' respective positions, as summarized in Section III. The Settlement Agreement is in the public interest and in the

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[21] Cal Advocates Direct Testimony of Ms. Vanessa Martinez, pp. 2-2 to 2-14; SBUA Direct Testimony of Paul Chernick and John D. Wilson, pp. 22 to 37.

[22] TURN Direct Testimony of Mr. Garrick Jones, pp. 22 to 24.

interest of SCE's customers. The Parties fairly represent the interests of the wide variety of customers and customer classes that are affected by the revenue allocation. The Agreement fairly resolves issues and provides more certainty to customers regarding their present and future costs, which is in the public interest.

The Settlement Agreement, if adopted by the Commission, avoids the cost of further litigation, and frees up Commission resources for other proceedings. Given that the Commission's workload is extensive, the impact on Commission resources is doubly important. The Settlement Agreement frees up the time and resources of the Commission and of the Parties, so that they may focus on other proceedings and the rate design portions of this proceeding. The prepared direct testimony contains sufficient information for the Commission to determine the reasonableness of the Settlement Agreement and to discharge any future regulatory obligation with respect to this matter.

D. <u>The Settlement Agreement Should Be Adopted as a Whole as it is a Compromise of Interests</u>

Each portion of the Settlement Agreement is dependent upon the other portions of the Settlement Agreement. Changes to one portion of the Settlement Agreement would alter the balance of interests and the mutually agreed upon compromises and outcomes that are contained in the Settlement Agreement. As such, the Settling Parties request that the Settlement Agreement be adopted as a whole by the Commission without modification, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

V.

<u>CONCLUSION</u>

WHEREFORE, the Settling Parties respectfully request that the Commission:

1. Approve the attached Settlement Agreement, without modification, as reasonable in light of the record, consistent with law, and in the public interest; and

2. Authorize SCE to implement changes in rates and tariffs in accordance with the terms of the Settlement Agreement.

Respectfully submitted,

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And on behalf of the Settling Parties.[23]

December 13, 2021

[23] In accordance with Rule 1.8(d), each Settling Party has authorized SCE's counsel to sign and file this motion on its behalf.

Attachment A
Marginal Cost and Revenue Allocation Settlement Agreement

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Dated: **December 13, 2021**

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MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the undersigned Settling Parties in Application (A.) 20-10-012, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, enter into this Marginal Cost and Revenue Allocation Settlement Agreement (Agreement or Settlement Agreement) with reference to the following:

1. PARTIES

The Settling Parties to this Agreement are Southern California Edison Company (SCE); The Utility Reform Network (TURN); the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Small Business Utility Advocates (SBUA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); California City-County Street Light Association (CALSLA); Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); and Direct Access Customer Coalition (DACC) (referred to hereinafter collectively as Settling Parties or individually as Party).[1]

A. SCE is an investor-owned public utility and is subject to the jurisdiction of the CPUC with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

[1] The following parties take no position on the Agreement: The Solar Energy Industries Association (SEIA); Enel X North America, Inc.; EVGo Services, LLC; Tesla, Inc.; Center for Accessible Technology (CforAT); California Choice Energy Authority (CCEA); the California Solar & Storage Association (CALSSA); and the Western Manufactured Housing Communities Association (WMA).

C. Cal Advocates represents the interests of public utility customers. Its mission is to obtain the lowest possible rate for service consistent with safe, reliable service, and the State's environmental goals. Pursuant to California Public Utilities Code Section 309.5(a), Cal Advocates is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

D. SBUA represents the interests of small commercial customers of bundled electricity as defined in California Public Utility Code Section 1802.

E. CFBF is California's largest farm organization, working to protect family farms on behalf of its nearly 34,000 members statewide and as part of a nationwide network of more than 5.5 million members.

F. AECA is a nonprofit organization representing the collective interests of many of the state's leading agricultural associations, and it works on behalf of the combined interests of several county farm bureaus and the individual farmers in more than forty agricultural water districts. AECA represents more than 40,000 California agricultural producers.

G. FEA represents the consumer interests of all Federal executive agencies that take utility service from SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

H. EUF is an *ad hoc* group that represents the interests of medium and large bundled service and DA customers in California, with locations in investor-owned utility and/or municipal utility service areas, primarily taking service on rate schedules for accounts with demand above 100 kW.

I. CMTA is a trade association representing the interests of 25,000 large and small manufacturers in California with 1.2 million employees. Many of its members receive electrical service from SCE either as bundled service or DA customers.

J. CLECA is an organization of large, high load factor industrial electric bundled service, CCA and DA customers located throughout the state. These companies are in the steel, cement, industrial gas, pipeline, minerals extraction, cold storage, food packaging, and beverage industries, and share the fact that electricity costs comprise a significant portion of their cost of production.

K. EPUC represents the end-use and customer generation interests of the following companies: Aera Energy LLC, Chevron U.S.A. Inc., California Resources Corporation, PBF Energy, Inc., and Phillips 66 Company.

L. CALSLA represents all California cities and counties, with the primary purpose of educating and advocating positions on street light rates.

M. DACC is a regulatory alliance of commercial, industrial, and governmental customers who have opted for DA service for some or all of their electric loads.

2. DEFINITIONS

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "BTUs" means British Thermal Units, which is commonly used as a measure of the energy capacity of natural gas.

B. "Basic Charge" means the fixed customer charge applied to customers in the Domestic Rate Group, as differentiated for single-family and multi-family residences.

C. "Bundled service customers" means those customers who take retail electric generation service from SCE.

D. "CA" means Community Aggregator.

E. "California Climate Credit," sometimes referred to as the Climate Dividend, means the portion of greenhouse gas (GHG) auction revenues returned on a per-account basis to residential customers pursuant to D.12-12-033.[2]

F. "CAISO" means the California Independent System Operator.

G. "Capacity Allocation Tool" provides a method for allocating annualized generation capacity marginal costs across hours of the year by determining a distribution of capacity shortfall events triggered by a scaled load forecast.

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[2] D.21-08-026 orders the IOUs to utilize a flat credit distribution method where qualifying small businesses receive a credit identical to the residential California Climate Credit at the same times the residential California Climate Credit is distributed. The change will be implemented with the 2022 ERRA Forecast rates.

H. "Collars" mean the restrictions (employed at the initial revenue allocation stage only), on delivery and generation revenue changes both above and below the Functional SAPC, as described in Paragraph 4.B.2., below.

I. "CCA" means Community Choice Aggregator.

J. "Customer Charge" means the fixed charge applied to customers in rate groups other than the Domestic Rate Group. See Basic Charge for Domestic Rate Group.

K. "DA" means Direct Access.

L. "Departing Load Customers" means those customers who take retail generation electric service from a provider other than SCE, and includes DA, CA, and CCA customers.

M. "DWR" means the California Department of Water Resources.

N. "EITE" means Emission-Intensive and Trade-Exposed customers, as those customers are defined in D.12-12-033. These customers receive GHG auction revenues pursuant to formulas adopted in D.14-12-037, as may be modified by the Commission.

O. "ERRA" means Energy Resource Recovery Account.

P. "FERC" means the Federal Energy Regulatory Commission.

Q. "Fixed Recovery Non-bypassable Charge" is a charge imposed on customers to pay the Recovery Bond principal, interest, and other related costs issued under Public Utilities Code § 850.1.

R. "Flexible Generation Capacity" (*i.e.*, "Flex") refers to the portion of generation capacity required to meet system ramping needs.

S. "Functional SAPC" allocation or "Functional SAPC basis" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the System Average Percent Change (SAPC) for the particular function, *e.g.*, distribution or generation.

T. "GHG allowance revenues" include the Greenhouse Gas (GHG) offsets, EITE and California Climate Credit.

U. "GHG costs" means the GHG costs ordered by the Commission to be collected in rates as a result of D.12-12-033.

V. "GHG offsets" means GHG allowance revenues used to offset delivery rates for small commercial and agricultural customers pursuant to D.12-12-033.

W. "Grid" when used in the context of distribution design demand marginal cost components, refers to the portion of distribution and subtransmission marginal costs that are not peak-related.

X. "Marginal Cost" means the change in total cost due to a small change in the quantity of an item produced or service provided.

Y. "NSGC" means New System Generation Charge, and is a cents per-kilowatt-hour charge included in SCE's delivery charges that recovers from all bundled service, CA, DA and CCA customers the revenues associated with facilities and resources that provide grid reliability for all electricity customers on its distribution system, as authorized by the Commission in D.09-03-031 and by SCE Advice Letter 2346-E (May 29, 2009).

Z. "NCO" means New Customer Only, and is a method used to derive marginal customer costs, taking into account the capital cost of adding new customers only and other O&M costs.

AA. "Non-Allocated Revenues" are revenues assigned directly to the rate groups that incur these costs, consisting primarily of Street Light Rate Group facilities' costs and power factor revenues, and which are excluded from SCE's allocation of its revenue requirement to all other rate groups.

BB. "Peak," when used in the context of distribution design demand marginal cost components, refers to the portion of distribution marginal costs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system. "Peak," when used in the context of generation marginal cost components, refers to that portion of the marginal costs that is incurred to support the electric system during maximum system demand.

CC. "PCIA" means the Power Charge Indifference Adjustment and is a rate that is paid by departing load customers as a separate line item on their bills.

DD. "Primary Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level between 12 kV and 33 kV, but always between 2 kV and 50 kV.

EE. "PPP" means Public Purpose Programs. PPP charges collect revenues for Commission-sponsored energy efficiency, renewable and research programs.

FF. "PUCRF" means Public Utilities Commission Reimbursement Fee.

GG. "RECC" or "Real Economic Carrying Charge," means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

HH. "RPS" means Renewables Portfolio Standard.

II. "Secondary Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level between 120 volts and 480 volts, but always less than 2 kV.

JJ. "SGIP" means Self Generation Incentive Program, with cost allocation as modified by Resolution E-4926.

KK. "SAPC" means "System Average Percentage Change," and it is the percentage difference in the system average rate when comparing one total authorized revenue requirement to another total system authorized revenue requirement. Functional SAPC allocations will be implemented periodically when SCE's authorized revenue requirements change after the initial implementation of this Agreement.

LL. "SAR" or "System Average Rate" is the average cents per-kilowatt-hour rate that applies to SCE's bundled service customers, based on SCE's authorized revenue requirements and a forecast of the CPUC-approved forecast level of sales.

MM. "Subtransmission Voltage" means the level of voltage at facilities at which electric power is taken or delivered, generally at a level greater than 50 kV and less than 220 kV.

NN. TOU" means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary in relation to the time-related cost of service. Unless otherwise stipulated, TOU periods means those that were adopted in Decision (D.)18-07-006.

OO. "Wildfire Fund Non-bypassable Charge" means the revenues collected by SCE to pay any bonds issued by DWR to fund the Wildfire Fund defined in Public Utilities Code Section 1701.8 and 3280 et seq.

3. <u>RECITALS</u>

A. Paragraph 4.B.7 of SCE's 2018 General Rate Case (GRC) Marginal Cost and Revenue Allocation Settlement Agreement, which was approved by D.18-11-027, applies to changes in SCE's authorized revenue requirements until a decision in this proceeding is implemented. SCE's rate groups are expected to receive revenue requirement changes that will be reflected in rates before this Agreement has been implemented. These revenue changes will have disparate impacts on each rate group based on the Functional SAPC allocation methodology and revenue allocators that apply to these revenue changes in accordance with D.18-11-027.

B. In Phase 2 of SCE's 2021 GRC, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each group.

C. On October 23, 2020, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in A.20-10-012.

D. On December 22, 2020, SCE served its supplemental testimony regarding wildfire revenue allocation proposal.

E. On January 20, 2021, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a December 16, 2020 prehearing conference.

F. Cal Advocates served its initial testimony on June 24, 2021.

G. On July 26, 2021, the following Settling Parties submitted prepared testimony regarding marginal costs and/or revenue allocation: TURN, SBUA, CFBF, AECA, CALSLA, DACC, CLECA, EPUC and FEA.

H. Cal Advocates served amended testimony on July 8, 2021 and on August 11, 2021.

I. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on August 12, 2021.

J. Continuing settlement discussions occurred among the parties after August 12, 2021.

K. Cal Advocates served supplemental testimony on revenue allocation, including rate collaring, on September 22, 2021.

L. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to marginal costs and the rate group allocation of SCE's authorized revenue requirement beginning with the implementation of a CPUC decision approving this Agreement, and have reached agreement as indicated in Paragraph 4 of this Agreement.

M. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to marginal costs and revenue allocation that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control.

N. Appendix B provides illustrative class average rate summaries based on a consolidated SCE revenue requirement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only and have no precedential value. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of this Agreement when rates are first implemented pursuant to the provisions of this Agreement.

4. AGREEMENT

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Settlement Agreement. The terms of the Settlement Agreement are interrelated and together represent the result of negotiations and compromises by the Settling Parties. Nothing in this Settlement Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit or that its position has greater or lesser merit than the position taken by any other Settling Party. Nothing in this Settlement shall be deemed an endorsement by any Party of any individual term of this Settlement. This Agreement is subject to the express limitation on precedent described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's 2025 GRC. Accordingly, the Settling Parties respectfully request that the Commission approve each and every aspect of the Settlement Agreement without modification.

A. Marginal Costs

This Settlement Agreement does not reflect approval or acceptance of any of the Settling Parties' marginal cost proposals. The Settling Parties agree that it is reasonable to use the marginal costs set forth in this Paragraph 4.A and use collars as described in Paragraph 4.B.2 on the initial revenue allocation results. These marginal costs were used to form the foundation of this revenue allocation agreement and may also be used as the basis for initial (though not binding) rate designs in subsequent potential rate design settlement agreements. They are strictly non-precedential pursuant to Paragraph 11.

1) **Generation Marginal Energy Costs**

Generation marginal energy costs (MECs) are based on an average forecasted total fuel cost of $5.65/MMBtu ($1.42/MMBtu GHG-related costs based on the Cap-and-Trade Program and $4.23/MMBtu based on SoCal Citygate gas price) in addition to a Renewables Portfolio Standard (RPS) adder forecast for the year 2024. Table RA-1 summarizes the MECs by season and TOU period.

Table RA-1
Generation Marginal Energy Costs (2024$)

2024 Marginal Energy Costs							
		Summer			Winter		
Vintage	Annual	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
¢/kWh	3.351	4.190	3.844	3.334	3.863	3.913	2.050

2) **Generation Capacity Marginal Costs**

The Generation Capacity Marginal Cost (GCMC) shall be $100/kW-year. Parties agree to use SCE's Capacity Allocation Tool to spread the GCMC across TOU periods and that it be partly allocated based on peak demand and partly based on the need for ramping capacity, i.e., flexible capacity. Table RA-2
Generation Marginal Capacity Costs (2021$) By TOU Periodoutlines the GCMC for Peak and Ramp by season and TOU period.

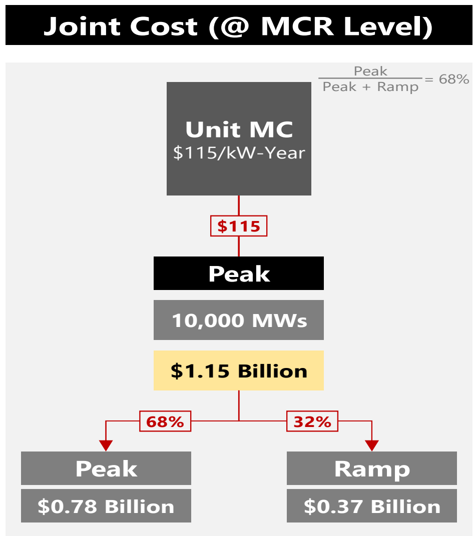
Table RA-2
Generation Marginal Capacity Costs (2021$) By TOU Period

2024 Generation Capacity Marginal Costs							
		Summer			Winter		
Vintage	Annual	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
Peak (% of MCR)	68%	61%	2%	5%	0%	0%	0%
Ramp (% of MCR)	32%	0%	0%	0%	32%	0%	0%
Combined $/kW-Yr	115.00	70.03	2.35	5.67	36.95	0.00	0.00

Capacity-related marginal costs include 15% Planning Reserve Margin ($115/kW-Year = $100/kW-Year * 115%).

Table RA-3 illustrates the derivation of Generation Capacity Marginal Cost Revenues using the agreed upon GCMC. The $115 GCMC value includes the $100/kW-yr. marginal cost of capacity plus a 15% planning reserve margin adder to account for resource adequacy requirements.[3]

Table RA-3
Derivation of Generation Capacity Marginal Cost Revenue (Illustration)



3) **Marginal Customer Costs**

For purposes of revenue allocation, marginal customer costs are determined based on a 50:50 ratio of SCE's RECC and TURN's NCO marginal customer costs calculations. The resulting marginal customer costs shall be as listed in Table RA-4, below:

[3] Exhibit SCE-02, SCE Testimony on Marginal Costs and Sales Forecast Proposals, p. 3.

Table RA-4
Marginal Customer Cost

	TURN's Monthly NCO Customer Cost 2021$		SCE's Monthly RECC Customer Costs 2021$		50:50 TURN NCO:SCE RECC Monthly Customer Costs 2021$
Domestic	4.82		10.94		7.88
GS-1	6.26		16.56		11.41
TC-1	3.61		8.33		5.97
GS-2	48.25		148.19		98.22
TOU-GS-3	103.51		286.60		195.06
TOU-8					
TOU-8-Sec	80.36		170.19		125.28
TOU-8-Pri	60.30		173.57		116.93
TOU-8-Sub	211.00		1,208.28		709.64
TOU-8-Standby					
Standby-Sec	80.36		170.19		125.28
Standby-Pri	60.30		173.57		116.93
Standby-Sub	211.00		1,208.28		709.64
TOU-PA-2	36.18		100.04		68.11
TOU-PA-3	128.45		245.04		186.74
Street Lights	3.64		8.84		6.24

4) <u>Marginal Distribution Capacity Cost</u>

For purposes of revenue allocation, marginal distribution capacity costs shall be consistent with SCE's proposal,[4] which provides the results listed in Table RA-5 below. The table below indicates that approximately 46 percent of the design demand marginal costs are peak-capacity related, and 54 percent of the costs are grid related. As discussed more fully in Paragraph 4.C below, SCE and interested parties agree to engage in discussions to explore the derivation of design demand marginal cost and the refinement of the peak/grid split for incorporation in SCE's next GRC Phase 2 proceeding.

[4] Exhibit SCE-02, Marginal Cost and Sales Forecast Proposals, pp. 25-51.

Table RA-5
Functionalized Distribution Marginal Cost by Asset Category and Asset Type

	System Design Demand ($/kW-year)	
	Grid	Peak
Non-ISO Subtransmission (66kV)	16.42	24.56
Distribution 12kV B-Bank	0.00	30.64
Distribution 12kV Circuit	80.87	28.54

B. <u>Revenue Allocation</u>

In order to avoid litigation, and to mitigate potentially adverse impacts on any particular rate group based on movement towards more cost-based rates in this proceeding, the Settling Parties agree to allocate SCE's total revenue requirement on an overall revenue-neutral basis. This Settlement Agreement is based on a number of assumptions as inputs to SCE's revenue allocation model. These assumptions were agreed upon by the Parties for the sole purpose of reaching this Settlement Agreement.

The Settling Parties agree that the illustrative revenue allocation results set forth in Appendix B of this Agreement are reasonable. However, the level of SCE's authorized revenues and CPUC-approved forecasted sales at the time that this Agreement will be implemented are presently unknown. Thus, this Agreement reflects the use of a consolidated SCE revenue requirement of $14,388 million in October 2021, which includes revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the Self-Generation Incentive Program (SGIP), Demand Response, the Wildfire Fund Non-bypassable Charge, Fixed Recovery Non-bypassable Charge, the New System Generation Charge (NSGC), and the GHG offsets.[5] The illustrative rate levels provided in Appendix B of this Agreement are based on this consolidated SCE revenue requirement and will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of this Agreement when rates are implemented pursuant to the provisions of this Agreement.

[5] California Climate Credit and the revenues to be returned to EITE customers are included in the consolidated SCE revenue requirement of $14,388 million, but are excluded during the revenue allocation and collaring process.

1) <u>Consolidated Revenue Requirement</u>

As noted immediately above, the 2021 consolidated revenue requirement of $14,388 million is based on SCE's revenue requirement effective as of October 1, 2021.

Table RA-6, below, provides additional details with respect to the assumed revenue requirements that are reflected in the 2021 consolidated revenue requirement.

Table RA-6
Consolidated Revenue Requirement Summary

	October 2021 Revenue Requirements ($000)		
	Total Retail	Bundled Service	Unbundled Service
Generation	**4,717,298**	**4,257,597**	**459,701**
ERRA (Fuel & Purchased Power + GHG Cost)	3,558,690	3,218,531	340,159
PABA/ERRA Balancing Account	462,138	312,050	150,088
GRC Phase 1	686,975	494,622	192,353
Other PCIA/CTC	0	219,132	(219,132)
Other Generation	9,495	13,262	(3,766)
New System Generation	**779,230**	**512,822**	**266,409**
Distribution	**6,597,535**	**4,534,777**	**2,062,757**
GRC - Distribution O&M and Capital (exclud. WF below)	5,485,188	3,786,024	1,699,163
Wildfire Risk-Mitigation Balancing Account (WRMBA)	10,648	7,350	3,299
Vegetation Management Balancing Account (VMBA)	65,250	45,037	20,213
Risk Mitigation Balancing Account (RMBA)	434,174	299,679	134,495
Non-Balancing Account Recovery	128,311	88,564	39,747
2021 GRC Memo Account	322,299	222,459	99,840
GRC Track 3			
Charge Ready / Transportation Electrification	25,118	17,337	7,781
WEMA/GSRP/WEMA2	252,500	174,283	78,217
CEMA	83,310	57,503	25,807
Demand Response	(6,722)	(4,640)	(2,082)
GHG Revenue	(330,882)	(247,403)	(83,479)
Other Distribution	128,339	88,583	39,756
Nuclear Decommissioning	**(43,059)**	**(27,659)**	**(15,400)**
Public Purpose Programs (PPP)	**577,935**	**380,120**	**197,815**
Energy Efficiency	123,058	80,101	42,958
CARE Administration	6,608	4,301	2,307
Other PPP	448,269	295,718	152,551
Transmission	**1,246,432**	**833,831**	**412,600**
AB 1054 Securitization (GSRP capex post Aug 1, 2019)	**19,257**	**13,292**	**5,965**
AB 1054 Securitization (Tracks 1 & 2 capex, Track 2 O&M)			
Wildfire Fund Non-Bypassable Charge	**393,138**	**246,853**	**146,285**
PUCRF	**100,183**	**64,352**	**35,830**
Total Revenue Requirement	**14,387,948**	**10,815,985**	**3,571,964**

A number of variables could either increase or decrease the revenue requirement when this Agreement is implemented and applied to SCE's authorized revenues. For bundled service customers, the consolidated revenue requirement in this Agreement represents a system average rate of 22.07¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's forecasted sales for 2021. For departing load customers, the consolidated revenue requirement in this Agreement represents a system average rate of 13.58¢/kWh (excluding the California Climate Credit and EITE revenue return).

2) Collars on Revenues Allocated to Rate Groups

As a result of the revenue allocation methods and marginal costs applied to SCE's authorized revenue requirements in SCE's Model (excluding the Incremental Amount of the Wildfire-related Revenue Requirement as described in Paragraph 4.B.5 subpart j) below), each rate group will receive different amounts of SCE's authorized revenue requirement relative to the change in the Functional SAPC. To promote rate stability, the revenue allocations and illustrative rates agreed to by the Settling Parties employ restrictions on delivery and generation revenue changes both above and below the Functional SAPC.

Except where otherwise specified, any revenue amount that would constitute an under-collection or over-collection of SCE's authorized revenues from a particular rate group resulting from the collar restrictions specified in Parts (a) and (b) of Paragraph 4.B.2 will be allocated to the rate groups that have not reached the respective generation or distribution revenue collars. After the collaring has been applied, the Incremental Amount of Wildfire-related Revenue Requirement shall be added back into the model. Table RA-7 and the subparts of Paragraph 4.B.2, below, describe these collars and illustrate the results.

Table RA-7
October 2021 Rates Compared to Capped Settlement Rates

Retail Delivery Distribution Capping
Direct Access and Bundled-Service Customers
(Excludes Incremental WF Revenues)

	Oct 2021 Retail Delivery Rate	Uncollared Retail Delivery Rate	Collared Retail Delivery Rate	Uncollared %	Collared %
Residential	15.95	14.72	15.03	-7.69%	-5.74%
GS-1	14.47	13.86	14.06	-4.23%	-2.85%
TC-1	19.29	12.40	18.18	-35.72%	-5.74%
GS-2	14.44	15.04	14.19	4.17%	-1.74%
TOU-GS-3	12.44	12.17	12.22	-2.17%	-1.74%
Total LSMP	13.90	13.98	13.62	0.53%	-2.01%
TOU-8-Sec	10.76	10.39	10.53	-3.39%	-2.15%
TOU-8-Pri	9.47	9.54	9.30	0.83%	-1.74%
TOU-8-Sub	4.69	4.63	4.61	-1.31%	-1.74%
Total LP	8.45	8.31	8.29	-1.73%	-1.95%
TOU-PA-2	12.18	11.23	11.48	-7.86%	-5.74%
TOU-PA-3	10.03	9.69	9.81	-3.41%	-2.23%
Total Ag.&Pumping	11.21	10.53	10.73	-6.07%	-4.32%
Total StLights	20.81	19.90	19.95	-4.41%	-4.15%
STANDBY/SEC	11.12	10.49	10.62	-5.63%	-4.49%
STANDBY/PRI	11.12	10.59	10.72	-4.79%	-3.60%
STANDBY/SUB	5.30	5.31	5.21	0.11%	-1.74%
Total Standby	6.74	6.61	6.57	-1.97%	-2.58%
System	12.96	12.47	12.47	-3.74%	-3.74%

Generation Capping
Bundled-Service Customers
(Includes Incremental WF Revenues)

	Oct 2021 Total Rate	Uncollared Bundled Delivery Rate	Collared Bundled Delivery Rate	Uncollared Generation Rate	Uncollared Total Rate	Collared Generation Rate	Collared Total Rate	Uncollared %	Collared %
Residential	25.40	15.27	15.54	9.99	25.26	9.86	25.40	-0.53%	-0.01%
GS-1	23.83	14.12	14.35	7.52	21.63	9.10	23.45	-9.20%	-1.57%
TC-1	26.64	13.11	19.00	7.74	20.85	7.64	26.63	-21.74%	-0.03%
GS-2	24.00	16.32	15.43	7.88	24.20	8.22	23.65	0.79%	-1.46%
TOU-GS-3	21.34	13.57	13.65	8.02	21.59	8.01	21.67	1.19%	1.54%
Total LSMP	23.35	15.10	14.75	7.82	22.91	8.41	23.15	-1.88%	-0.85%
TOU-8-Sec	18.52	11.09	11.26	7.45	18.55	7.35	18.61	0.13%	0.46%
TOU-8-Pri	16.66	10.12	9.89	7.50	17.62	7.02	16.91	5.81%	1.53%
TOU-8-Sub	11.16	4.83	4.84	6.97	11.80	6.49	11.32	5.71%	1.46%
Total LP	16.03	9.15	9.16	7.34	16.48	7.03	16.19	2.80%	0.95%
TOU-PA-2	20.13	11.65	11.93	7.51	19.16	7.88	19.82	-4.82%	-1.56%
TOU-PA-3	16.91	10.22	10.36	7.60	17.81	6.80	17.16	5.32%	1.46%
Total Ag.&Pumping	18.71	11.02	11.24	7.55	18.57	7.41	18.65	-0.78%	-0.36%
Total StLights	24.61	19.10	19.16	9.20	28.30	5.76	24.92	14.98%	1.25%
STANDBY/SEC	18.19	10.71	10.72	7.60	18.31	7.50	18.22	0.68%	0.18%
STANDBY/PRI	18.79	11.23	11.39	7.41	18.64	7.31	18.70	-0.81%	-0.50%
STANDBY/SUB	11.30	5.47	5.40	6.91	12.38	6.05	11.44	9.51%	1.25%
Total Standby	12.98	6.76	6.73	7.03	13.79	6.35	13.08	6.24%	0.73%
System	22.10	13.48	13.50	8.57	22.05	8.57	22.07	-0.20%	-0.14%

Delivery Collar:	Limits
All rate groups: SAR - 2.0% cap	-1.74%
All rate groups: SAR - 2.0% floor	-5.74%

Generation Collar:	Limits
All rate groups: SAR + 1.5% cap	1.36%
All rate groups: SAR - 1.5% floor	-1.64%

Notes:
Collar Limits are based on the System Average Rate delta, plus or minus the cap/floor percentages
Bundled Average Rates will no longer follow collar, because of the incremental WF revenues layered onto capped revenues

Table RA-8, below, lists the functional revenue allocator percentages that shall be used to allocate each unbundled revenue requirement to each rate group based on the above principles. For the Grid portion of distribution design demand marginal cost, distribution revenue allocators were initially derived, in part, from non-coincident peak values taken from a three-year average (2017-2019), as reflected in SCE's work papers. For Schedules TOU-PA-2 and TOU-PA-3, the non-coincident peaks are based on a seven-year average of non-coincident peak demands spanning 2013-2019. This adjustment was made in order to encompass a broader range of potential hydrological conditions to be reflected in the billing determinants for agricultural and pumping customers, and the adjustment impacted the balance of distribution revenue allocators accordingly.

Table RA-8
GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

	Uncollared	Collared	Uncollared	Collared						
	Distribution		Generation		APS & Interruptible Surcharge[1]	SGIP[2]	PPP[3]	NDC/PUCRF[4]	NSGC[5]	Wildfire Special Allocator
Total Domestic	50.6%	51.3%	47.3%	46.6%	42.5%	23.0%	41.9%	35.3%	44.0%	44.9%
GS-1	7.3%	7.5%	7.1%	8.6%	6.4%	2.4%	7.9%	7.1%	7.3%	7.7%
TC-1	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
GS-2	18.8%	17.1%	14.1%	14.7%	14.6%	12.9%	17.3%	15.8%	15.8%	17.8%
TOU-GS-3	7.4%	7.6%	6.6%	6.6%	8.1%	18.0%	8.4%	8.8%	8.2%	8.0%
Total LSMP	33.5%	32.3%	27.9%	30.0%	29.1%	33.3%	33.6%	31.8%	31.4%	33.6%
TOU-8-Sec	6.7%	7.0%	7.2%	7.1%	8.6%	13.6%	8.2%	9.7%	8.4%	7.8%
TOU-8-Pri	4.4%	4.3%	4.8%	4.6%	6.2%	10.9%	5.0%	6.5%	5.0%	5.1%
TOU-8-Sub	1.1%	1.4%	6.6%	6.3%	8.2%	0.0%	4.1%	7.7%	5.0%	3.9%
Total Large Power	12.3%	12.7%	18.6%	18.0%	23.0%	24.5%	17.3%	23.9%	18.4%	16.9%
TOU-PA-2	1.9%	2.0%	2.5%	2.6%	2.0%	6.9%	2.2%	2.3%	1.6%	2.1%
TOU-PA-3	1.1%	1.2%	2.0%	1.8%	1.7%	8.2%	1.5%	1.9%	1.3%	1.4%
Total Ag.&Pumping	3.0%	3.1%	4.4%	4.3%	3.7%	15.0%	3.6%	4.1%	2.9%	3.4%
Total Street Lighting	0.2%	0.2%	0.8%	0.5%	0.8%	0.0%	0.9%	0.7%	0.4%	0.6%
STANDBY/SEC	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.2%	0.2%	0.2%	0.1%
STANDBY/PRI	0.2%	0.2%	0.3%	0.2%	0.2%	3.0%	0.7%	0.8%	0.6%	0.2%
STANDBY/SUB	0.1%	0.0%	0.7%	0.2%	0.6%	1.2%	1.7%	3.2%	2.1%	0.3%
Total Standby	0.4%	0.3%	1.0%	0.6%	0.9%	4.2%	2.6%	4.2%	2.9%	0.6%
Total System	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

a) **Delivery Service Collars for Allocated Revenues (Affects Departing Load and Bundled Service Customers)**

For the delivery service collar, the Settling Parties agree to remove all GHG allowance revenues from the consolidated revenue requirement in Table RA-6. The Settling Parties agree to allocate delivery service revenues to the rate groups in accordance with the collared allocators shown in Table RA-8 using a collar of the Functional SAR change for delivery services plus or minus 2.0 percent.

b) **Generation Revenue Collars on Bundled Service Rates (Affects Bundled Service Customers Only)**

For the generation revenue collar, the Settling Parties agree not to remove the GHG costs from the consolidated revenue requirement. The Settling Parties agree to allocate generation service revenues to bundled service customers in the rate groups in accordance with the collared allocators shown in Table RA-8, using a collar of the SAR change for (bundled) generation services plus or minus 1.5 percent.

3) Establishment of Street Light Rate Group Non-Allocated Revenues

For revenue allocation purposes, the Settling Parties agree that Non-Allocated Revenues specifically assigned to the Street Light rate group shall be initially established at a level of approximately $78 million. The level of the Non-Allocated Revenues assigned to the Street Light rate groups in attrition years, including the split of the recovery of non-allocated revenues between street light facilities charges and distribution energy charges, shall be addressed in the rate design phase of this proceeding.

4) Allocation of CPUC and FERC-Authorized Revenue Requirements

The Settling Parties agree that all of SCE's CPUC- and FERC-jurisdictional revenue requirements as reflected in the consolidated revenue requirement shall be allocated as specified in Paragraph 4.B.5, below, to produce the allocation of revenues and corresponding rate levels for each rate group set forth in Appendix B. As provided in Paragraph 4.B.6, below, the consolidated revenue requirement shall be adjusted to reflect SCE's actual total system revenue requirement using SCE's Model when rates based on this Agreement are implemented. Revenue changes and illustrative rates for both bundled service and departing load customers based on the consolidated revenue requirement are also shown in Appendix B.

5) Functional Revenue Requirements

SCE's authorized functional revenue requirements shall be allocated to rate groups as follows:

a) FERC-Jurisdictional Transmission Revenue Requirement

SCE's FERC-approved rate revenues shall be adjusted up or down in proportion to any change in FERC-authorized revenues. The applicable FERC-jurisdictional revenue requirement that is reflected in the consolidated revenue requirement shall be allocated to each rate group based on the 12 monthly system coincident peak (12-CP) revenue allocators shown in Table RA-8. FERC-jurisdictional rate components shall be added to the CPUC-jurisdictional delivery rates, resulting in total delivery service rates.

b) Distribution-Related Revenue Requirement

1) Subject to the collaring stages described in Paragraph 4.B.2 subpart a), above, as shown in Table RA-7, above, SCE's distribution revenue requirement reflected in the consolidated revenue requirement shown in Table RA-6 shall be allocated to rate groups based on the applicable distribution functional allocators shown in Table RA-8.

2) For purposes of revenue allocation, the revenue requirement resulting from interruptible rate program credits (*e.g.*, Base Interruptible Program, Summer Discount Plan (SDP), and Agricultural/Pumping-Interruptible), shall be based upon SCE's forecast of program participation and credit levels using the methodology adopted in D.17-12-003. These costs shall be allocated to rate groups for recovery in distribution rates from bundled service and departing load customers based on the system generation allocators shown in Table RA-8.

3) SCE will eliminate the tracking of Conservation Incentive Adjustment (CIA) balances as a separate amount recorded in the Public Purpose Program Mechanism (PPPAM) that is only recorded from residential customers. SCE will now recover the amount from all customers, similar to other forecast-related imbalances, by recording any balance to the distribution sub-account of SCE's Base Revenue Requirement Balancing Account (BRRBA-D).

4) Non-Allocated Revenues shall be assigned directly to the rate groups responsible for incurring the costs. Paragraph 4.B.3, above, specifies the level of Non-Allocated Revenues assigned to the Street Light rate group.

5) The revenues associated with the discount provided to SCE's employees and retirees under Schedule DE shall be allocated to all other customers, except customers receiving the CARE discount, on an equal cents per-kilowatt-hour basis including all retail sales. The charge for the DE discount is reflected in the PPP charge.

c) **<u>SCE Generation Revenue Requirement</u>**

Subject to the collars described in Paragraph 4.B.2 subpart b), above, and as shown in Table RA-7, above, the generation revenue requirement reflected in the consolidated generation revenue requirement, net of contributions, *e.g.*, PCIA from departing load customers, shall be allocated to rate groups based on the generation functional allocators shown in Table RA-8, above.

d) Wildfire Fund Non-bypassable Revenue Requirement

The Wildfire Fund Non-bypassable revenue requirement shall be recovered based on the Wildfire Fund Non-bypassable Charge as authorized in D.20-09-023, which is on an equal cents per-kilowatt-hour basis, including all retail sales excluding CARE customers.

e) Nuclear Decommissioning Revenue Requirement

In accordance with D.00-06-034, SCE's CPUC-jurisdictional, nuclear decommissioning revenue requirement shall be allocated to all rate groups, based on energy consumption reflecting total retail sales as indicated in Table RA-8, above, and shall be recovered on an equal cents per-kilowatt-hour charge designated in SCE's tariffs as the NDC.

f) Public Purpose Programs (PPP) Revenue Requirement

SCE's non-CARE PPP revenue requirement shall be allocated based on each rate group's percentage share of system revenues for bundled service and departing load customers with generation revenues for departing load customers imputed as if they were bundled service customers. The PPP revenue requirement allocated to each rate group in this manner shall be recovered from the customers of each respective rate group on a cent per-kilowatt-hour basis. CARE Balancing Account and CARE Administration revenues within PPP shall be allocated based on each rate groups percentage of revenues as stated above for PPP allocation, however the allocation factor for these two items is determined by excluding the associated CARE and Streetlight revenues, thereby exempting CARE and Streetlight customers from these two charges. The Tree Mortality Non-Bypassable Charge (TM-NBC) and BioMat Non-Bypassable Charge (BMNBC) are other components that are set on a cents per-kilowatt-hour basis and added to PPP rate component once allocated. The revenue requirement associated with TM-NBC and BMNBC are allocated using the 12-month coincident peak (CP) demand allocator as adopted in D.18-12-003 and D.20-08-043.

g) CARE Discount

The revenues associated with the discount provided to CARE customers shall be allocated to rate groups on an equal cents per-kilowatt-hour basis including departing load sales, but excluding the kWh usage of CARE and Street Light customers. The CARE revenue requirement shall be recovered through a surcharge added to all customers' rates, excluding CARE customers themselves and customers in the Street Light rate group. The CARE surcharge is reflected in the PPP charge.

h) <u>SGIP Revenue Requirements</u>

The SGIP revenue requirement that is reflected in the consolidated revenue requirement (Table RA-6) shall be allocated to rate groups based on the SGIP revenue allocator listed in Table RA-8, and consistent with recent Commission direction in Resolution E-4926, which is based on the proportion of SGIP incentives disbursed to different rate groups over the most recent three years. The allocation will be updated annually on a rolling basis. The SGIP revenue requirement will be recovered in non-CARE-customers' rates on a cents-per-kilowatt-hour basis in the Public Purpose Programs Charge.

i) <u>New System Generation Revenue Requirement</u>

The NSG revenue requirement shall be allocated using the 12 monthly system coincident peak (12-CP) revenue allocators shown in Table RA-8.

j) <u>Wildfire-Related Revenue Requirement</u>

Wildfire-related Revenue Requirement (WRR) refers to existing and future Commission-authorized revenue requirements and fixed recovery charges that fall within the following categories: (1) wildfire-related costs authorized in GRC base rates,[6] including but not limited to costs tracked in the following accounts: Wildfire Risk Mitigation Balancing Account;[7] Vegetation Management Balancing Account;[8] and Risk Management Balancing Account;[9] (2) wildfire-related costs

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[6] Wildfire-related costs authorized in the GRC includes, but are not limited to, those costs identified in Section 17 of D.21-08-036. Such costs include, for example, capital expenditures for wildfire risk mitigation and wildfire-related O&M. "Capital expenditures for wildfire risk mitigation" refers to those utility distribution capital costs subject to Section 8386(e) of the Public Utilities Code, as well as other utility distribution infrastructure costs related to fire risk mitigation. "Wildfire-related O&M" refers to O&M expenses related to catastrophic wildfires.

[7] The two-way Wildfire Risk Mitigation Balancing Account (WRMBA) records the difference between the Wildfire Covered Conductor Program (WCCP) capital expenditures authorized in Track 1 of SCE's 2021 GRC Decision (D.) 21-08-036 and SCE's recorded (actual) WCCP capital expenditures. The capital-related revenue requirements for actual WCCP expenditures in excess of a 110 percent reasonableness threshold are subject to additional reasonableness review prior to recovery from customers.

[8] The two-way Vegetation Management Balancing Account (VMBA) records the difference between authorized O&M expenses adopted in D.21-08-036 for vegetation management activities and actual O&M expenses for vegetation management activities. Actual O&M expenses that exceed 115 percent of the authorized amount are subject to additional reasonableness review prior to recovery from customers. Wildfire-related costs tracked in the VMBA include, for example, wildfire vegetation management through SCE's Hazard Tree Management Program, and dead, dying and diseased tree removal.

[9] The one-way Risk Management Balancing Account (RMBA) records the difference between actual insurance premium expenses for wildfire liability coverage, including the costs of alternative risk transfer instruments, and the authorized insurance premium expenses for wildfire liability coverage adopted in D.21-08-036.

authorized in proceedings other than the GRC that review the reasonableness of the following accounts: Catastrophic Event Memorandum Account;[10] Wildfire Expense Memorandum Account;[11] Wildfire Mitigation Plan Memorandum Account;[12] Fire Risk Mitigation Memorandum Account;[13] and other Commission-authorized balancing and memorandum accounts that may be established that include wildfire-related costs; and (3) wildfire-related costs that are authorized to be recovered through a Fixed Recovery Non-bypassable Charge. The WRR shall be recovered through distribution rates and shall be allocated using the formulaic approach described below.

(1) <u>WRR Allocation and Determination of Special Allocator Formula</u>

The WRR shall be separated into two parts, a capped and incremental amount, and each part shall be subject to a different allocation. The capped and incremental revenue allocations will be combined to develop a composite weighted average allocator ("Special Allocator") for each customer class.

(a) <u>Capped Revenue Allocation</u>

The revenues for up to the first $525 million ("WRR Capped Amount") will be allocated using a 50 percent / 50 percent average of the distribution allocator and system average percent (SAP) allocator,[14] respectively. The annual WRR cap of $525 million will remain fixed until the next GRC Phase 2 is resolved. During the initial implementation of this Settlement Agreement, the $525 million amount will be allocated among the functional revenues before any rate collaring is applied to the overall changes to revenue allocation.

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[10] The Catastrophic Event Memorandum Account (CEMA) includes, in pertinent part, incremental capital expenditures and O&M for restoration and/or repair of SCE's facilities as a result of a wildfire that is declared a disaster by a competent state or federal authority.

[11] The Wildfire Expense Memorandum Account (WEMA) includes, for example, wildfire liability claims payments, litigation costs and associated financing costs (in excess of amounts covered by insurance, and net of third-party credits), as well as payments made for liability and property wildfire insurance.

[12] The Wildfire Mitigation Plan Memorandum Account (WMPMA) includes, for example, incremental costs incurred to implement SCE's Wildfire Mitigation Plan (WMP) that are not otherwise covered in SCE's revenue requirements or tracked in another ratemaking account.

[13] The Fire Risk Mitigation Memorandum Account (FRMMA) includes, for example, incremental costs incurred for fire risk mitigation that are not otherwise covered in SCE's revenue requirements or recorded in another memorandum accounts such as the WMPMA or the CEMA.

[14] SAP allocator is based on each rate group's percentage share of system revenues for bundled service and departing load customers with generation revenues for departing load customers imputed as if they were bundled service customers.

(b) Incremental Revenue Allocation

The "WRR Incremental Amount" is all amounts of WRR that exceeds the $525 million and will be allocated using a 12.5 percent / 87.5 percent average of the distribution allocator and SAP allocator, respectively. This WRR Incremental Amount is added to the model after the overall revenue allocation collaring is performed, and is not subject to the collaring process.

(c) Special Allocator

The Special Allocator is a composite weighted average allocator that combines the distribution and SAP weights multiplied by the respective class allocators.

$$\text{Special Allocator}_i = (\text{Distribution Weight*Distribution Allocator}_i) + (\text{SAP Weight*SAP Allocator}_i)$$[15]

Below is an example intended only to provide an illustration of how the Special Allocator is developed:

1. Starting with a total annual WRR of $898 million as of October 2021, $525 million is the WRR Capped Amount and $373 million is the WRR Incremental Amount.
2. The WRR Capped Amount of $525 million is allocated by class:

   $525 million ((50% * Distr. Allocator$_i$) + (50% * SAP Allocator$_i$))
3. The WRR Incremental Amount of $373 million is allocated by class:

   $373 million ((12.5% * Distr. Allocator$_i$) + (87.5% * SAP Allocator$_i$))
4. The Special Allocator (%) for each customer class is the sum of the WRR Capped Amount and the WRR Incremental

[15] Subscript "*i*" in the formula denotes the allocator assigned to each rate class.

Amount for that class divided by the total WRR, as shown in Table RA-8.

Once the Special Allocator is established for each class, it will also be used to allocate any additional WRR authorized for rate recovery during the year until the next annual adjustment. The Special Allocator will be adjusted annually during the attrition years, concurrent with the annual sales forecast adjustment, to account for the then-current amount of the total annual WRR. The average distribution and SAP allocators will be updated annually to reflect changes to the billing determinants (sales), each class's percentage share of total system revenues, and the Distribution and SAP weights. These updates will be inputted using the formulas above to derive the Special Allocator that will be used during each year.

(2) <u>Securitized Wildfire-Related Revenue Requirements</u>

- Wildfire-related revenue requirements that are subject to Recovery Bonds that are recovered through a Fixed Recovery Non-bypassable Charge[16] are considered part of the overall WRR that is considered during the development of the Special Allocator.
- The existing revenue allocation associated with wildfire-related securitization adopted in D.20-11-207 and D.21-10-025 shall be retained and unaffected by the Special Allocator.
- To retain the Special Allocator computed from the WRR allocation formula while also retaining the revenue allocation established for a securitized amount pursuant to its applicable Commission Financing Order, SCE shall establish each customer class's allocation of the non-securitized portion of the WRR such that the total weighted allocation for that class (i.e., the securitized allocation and the non-securitized allocation) conforms to the Special Allocator.
- For future wildfire-related securitizations, the Special Allocator shall be used to establish the allocation of the securitized

[16] Inclusive of Recovery Bond principal, interest, and related costs.

amount. The Special Allocator effective at the time SCE files a request for authorization to issue Recovery Bonds will be used to establish a fixed allocation factor for the life of the bond,[17] with adjustment for sales changes as necessary to ensure collection of the necessary Commission-authorized revenue requirement.

k) <u>Transportation Electrification (TE) Allocation</u>

Allocation and recovery of TE related revenue requirements attributable to the four programs listed below will maintain the allocation and recovery methods directed in each program's respective decision:

- Charge Ready Phase 1 Pilot – Distribution Allocation (D.16-01-023 & D.18-12-006);
- Charge Ready School and Parks – Distribution Allocation (D.19-11-017)
- Transportation Electrification – Distribution Allocation (D.18-01-024 & D.18-05-040);
- Charge Ready 2 – Equal Cents Allocation, recovered through distribution rates (D.20-08-045); and
- The above four program costs will continue to be recovered through distribution rates.

Settling Parties agree the above-described TE allocation and recovery methodologies do not apply to future TE programs that SCE may propose. Any such future TE program application will be subject to the cost allocation authorization made in the proceeding that authorizes the program and associated funding.

[17] Revenue allocation between customer classes will ultimately differ from the Special Allocator due to CARE/FERA exemption for securitized revenues pursuant to Public Utilities Code Section 850.1. The CARE/FERA exempted revenues will be reallocated to the non-exempted classes in proportion to each respective class's contribution to the initially determined Special Allocator.

6) **<u>Adjustments to Revenue Requirements When Agreement Is First Implemented</u>**

The revenues and rates reflected in Appendix B are illustrative and based on the consolidated revenue requirement of $14,388 million as described in Paragraph 4.B.1, above. To the extent SCE's actual authorized revenue requirement varies from this total when this Settlement Agreement is implemented, the following process will be used:

- Using the consolidated revenue requirement, SCE will adjust sales and demand to reflect SCE's forecast of sales and demand per billing period that is derived from the most recent approved ERRA forecast proceeding. During this process, SCE will use billing determinants derived from overall bundled service, CA, DA and CCA customer forecast sales, then run SCE's Model with the same input assumptions for marginal costs that were used to develop the allocation settlement including delivery and generation collaring, the allocation of generation revenue requirements, distribution revenue requirements, SGIP, WRR, and other revenue requirements that are reflected in this Agreement, and any updated FERC 12-CP transmission factors, if necessary.
- After removing Street Light rate group Non-Allocated Revenues and other Non-Allocated Revenues, SCE will develop the revised collared functional revenue allocators; and
- To complete the revenue allocation process, SCE will apply the revised collared functional distribution and generation revenue allocators to the revised CPUC-authorized revenue requirements, add the Incremental Amount of the Wildfire-related Revenue Requirement, FERC-authorized revenue requirements per rate group, add the Street Light rate group Non-Allocated Revenues back to the Street Light rate group and add back other Non-Allocated Revenues so as to develop the portion of SCE's authorized revenue requirement that is allocated to each rate group.

7) Future Changes to SCE's Consolidated Revenue Requirement

a) Future Distribution and Generation Revenue Changes

The Settling Parties agree that distribution and generation revenue requirement changes occurring after the Commission has issued a decision in this proceeding and until Phase 2 of SCE's next GRC proceeding is implemented shall be allocated using the functional allocators used in this Agreement.

For consolidated rate changes resulting from revenue changes associated with SCE's ERRA(s) or GRC, SCE will adjust the rate levels for the base rate schedules, *e.g.*, Schedule D or Schedule TOU-8-Sec-D, using a Functional SAPC adjustment. The four main steps to this adjustment are:

1. For ERRA-related revenue changes, SCE will update the forecasted billing determinants. For non-ERRA revenue changes, SCE will use the then-currently authorized forecasted billing determinants;
2. Using the billing determinants from Step 1, above, SCE will calculate the present rate revenues. SCE will then compare the present rate revenues to the authorized rate revenues to determine the Functional SAPC adjustments (including various revenue adjustments such as for non-allocated revenue requirements, kVAR adjustments and GHG allowances, etc.);
3. For WRR, the Special Allocator will be adjusted annually during the annual implementation of SCE's ERRA Forecast proceeding to account for the then-current amount of the total annual WRR. The amount of annual WRR will be calculated and the weighted distribution and SAP allocators will be applied using the formulas as described in Paragraph 4.B.5 subpart j) above and reflecting the sales forecast adopted in the ERRA decision to arrive at the Special Allocator that will be used for the year.
4. The Functional SAPC adjustments from Step 2, above, will be applied to each rate component associated with that function. For example, the revised SCE generation revenue requirement resulting from SCE's ERRA proceedings will be allocated by applying a generation-level

SAPC scalar based on the difference between present rate revenues and authorized rate revenues to the generation-related rate components for the default rate schedules; and

5. SCE will then rebalance optional rate levels to ensure revenue neutrality (for distribution and generation revenues) between the default rate schedule and the optional rate schedules on a functional basis using recorded (not forecast) billing determinants.[18]

b) Future SGIP Revenue Requirement Changes

Notwithstanding Paragraph 4.B.7(a), above, after this Agreement is implemented, whenever SCE's authorized revenue requirements change, the authorized SGIP revenue requirements shall be allocated using the SGIP revenue allocators listed in Table RA-8. For future SGIP revenue changes, the difference between the SGIP revenues reflected in the consolidated revenue requirement ($56.6 million shown in Table RA-6) and future authorized revenue requirements will be allocated using this methodology.

c) Energy Efficiency Shareholder Incentives

When this Agreement is implemented and for future revenue allocations after this Agreement is implemented, any energy efficiency shareholder incentives shall be allocated so that 50 percent is allocated by each rate group's proportional share for system revenues, with generation revenues for departing load customers imputed as if they were bundled service customers, and the remaining 50 percent is allocated by the collared distribution revenue allocators in Table RA-8.

d) Future Demand Response Revenue Requirement Changes

Notwithstanding Paragraph 4.B.7(a), unless the CPUC directs a change to the allocation of demand response program administration and incentive revenue requirements in a future proceeding, the collared distribution revenue allocators, excluding revenues for SGIP, shareholder energy efficiency incentives, and street light facilities, applied to demand response revenue requirements shall be modified so that 50 percent of the demand response program administration and incentive revenue requirement will be allocated by each rate group's proportional share of system revenues, with

[18] This calculation is performed by multiplying these billing determinants by the current rates. Adjustments to account for customers served on TOU-EV-8 & TOU-EV-9 rates will be made such that any revenue deficiency is contained within the individual rate class (*e.g.*, TOU-GS-2, TOU-GS-3, TOU-8) in which the deficiency exists.

generation revenues for departing load customers imputed as if they were bundled service customers, and the remaining 50 percent of the demand response program administration and incentive revenue requirement will be allocated by the collared distribution revenue allocators in Table RA-8.

C. Future Distribution Design Demand Marginal Cost Study

Settling Parties agree that within one year of the adoption of this Agreement, SCE will initiate a working group with interested parties to discuss best practices and methodologies in the determination of Design Demand Marginal Costs (DDMC) for the purposes of revenue allocation and rate design. In particular, the working group will seek to understand cost factors such as load, installed capacity, distribution investment, and line miles used when defining design demand marginal costs, the peak/grid split, and the allocation of such costs to customer classes. Participants in the working group process will be encouraged to propose the kinds of data that SCE should collect. This data could be used for parties' testimony in SCE's 2025 GRC Phase 2 and for the study described in this section. In the interim, if the desired data is not yet available, the parties should discuss methodologies to accommodate that gap or availability of alternative data. In testimony, Cal Advocates and SBUA have proposed alternative methodologies that can be explored by parties.[19]

TURN has suggested that the working group include a review of megawatt measures used in the DDMC analysis. TURN's analysis recognizes the difference in measures of MWs (installed capacity) that are used in SCE's DDMC regression analysis to calculate the marginal delivery costs, and the measure of MWs (consumer group hourly load) used to allocate marginal delivery costs to classes.[20] The working group will identify methodologies, including the use of "scalars" as advocated in TURN's testimony or other solutions, to ensure that the model captures and appropriately applies all costs for the purposes of revenue allocation and rate design. Other stakeholders, such as PG&E, SDG&E, and the Commission's Energy Division, will be invited to participate in these discussions. Upon conclusion of the working group's efforts, which may result in a workshop, SCE shall perform one or more studies, the results of which shall be served on the Settling Parties when SCE files its 2025 GRC Phase 2 Application (and serves its supporting testimony), that will explore the determination of DDMC, and which may be used for proposing refinements to SCE's current approach for cost determination, and revenue allocation.

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[19] Cal Advocates Direct Testimony of Ms. Vanessa Martinez, pp. 2-2 to 2-14; SBUA Direct Testimony of Paul Chernick and John D. Wilson, pp. 22 to 37.

[20] TURN Direct Testimony of Mr. Garrick Jones, pp. 22 to 24.

5. IMPLEMENTATION OF SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2022.

6. INCORPORATION OF COMPLETE AGREEMENT

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. Except as outlined in Paragraph 9, if the Commission does not approve this Agreement in its entirety without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

7. RECORD EVIDENCE

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

8. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

9. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's 2021 GRC. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that

Settling Party shall notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. NON-PRECEDENTIAL

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission.

12. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to marginal cost and revenue allocation issues. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. NON-WAIVER

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. EFFECT OF SUBJECT HEADINGS

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. GOVERNING LAW

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: December 13, 2021

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Senior Vice President, Regulatory Affairs

Dated: December 13, 2021

THE UTILITY REFORM NETWORK

/s/ David Cheng

By: David Cheng
Title: Staff Attorney

Dated: December 13, 2021

SMALL BUSINESS UTILITY ADVOCATES

/s/ James Birkelund

By: James Birkelund
Title: President

Dated: December 13, 2021

PUBLIC ADVOCATES OFFICE

/s/ Linda Serizawa

By: Linda Serizawa
Title: Deputy Director

Dated: December 13, 2021

CALIFORNIA FARM BUREAU FEDERATION

/s/ Kevin Johnston

By: Kevin Johnston
Title: Associate Counsel

Dated: December 13, 2021

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

/s/ Michael Boccadoro

By: Michael Boccadoro
Title: Executive Director

Dated: December 13, 2021

FEDERAL EXECUTIVE AGENCIES

/s/ Rita Liotta

By: Rita M. Liotta
Title: Counsel

Dated: December 13, 2021

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Counsel

Dated: December 13, 2021

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Attorney

Dated: December 13, 2021

ENERGY PRODUCERS AND USERS COALITION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Attorney

Dated: December 13, 2021

ENERGY USERS FORUM

/s/ *Robert Kehrein*

By: Robert Kehrein
Title: Executive Director

Dated: December 13, 2021

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

/s/ Daniel Denebeim

By: Daniel Denebeim
Title: Attorney

Dated: December 13, 2021

DIRECT ACCESS CUSTOMER COALITION

/s/ Daniel Douglass

By: Daniel W. Douglass
Title: Counsel

Appendix A

Comparison of Party Positions and Settlement

Revenue Allocation

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
Capping / Collaring	Did not propose	Collaring: Delivery: +/-6% Generation: +/-6% Proposed in Supplemental Testimony	Collaring Bundled: +/-3% Delivery: +/-6% Treat A&P as single class		Support cap (and floor) to the revenue allocation changes			Supports capping Don't mix across delivery and generation	Did not propose but supports capping; potentially address capping separately for small and large Ag depending on RA		Propose capping both the distribution and generation class rates at +2%	Collaring: Delivery: +/-2% Generation: +/-1.5%
Generation Revenues	Allocate to bundled service customers in each rate group based on marginal generation costs, after first being adjusted for expected CRS revenue from DA and CCA customers Generation Energy MCRR: 58% Generation Capacity MCRR: 42% Generation energy MCRR - determined by multiplying MECs by the forecasted	Proposes to treat the peak-related and flexibility capacity function of GCMC as joint product to reflect that the same battery would provide both services. Allocates 25% cost to peak and 75% to flex to reflect a 4-hour lithium battery would theoretically provide 3 hours of ramping capacity and	Recommends that, if the Commission declines to adopt Cal Advocates' recommendation and instead adopt separate allocation for peak and flex capacity, the Commission should remove the generation-related contributions to net load for purposes of allocation from the	Recommends all costs be allocated to peak capacity as proposed by PG&E Recommends the use of PG&E's Adjusted Net Load method Disagree with Cal Advocates' recommendation to change the assignment method for DG related costs	Agrees with SCE that the peak requirement for generation capacity is separate from ramp requirement. The peak and ramp capacity costs are separate and not a joint cost. Peak & Ramp MWs should be differentiated based on Retail-to-Bundled sales for each customer group	Recommends SCE's 2021 forecasted bundled sales % for each customer class be used to determine bundled load responsibilities for peak and ramp capacity Disagree with Cal Advocates' proposal to treat peak and ramping as a joint cost driver	Recommend that when the bundled load responsibilities for peak and ramping capacity are determined for each customer class, SCE's 2021 forecasted bundled sales percentages for each customer class be used consistent with SCE's assumptions for rate design in		Opposed Cal Advocates' proposal to use a "shared cost" model	Generation cost allocation, at least for agriculture, should remain frozen in this GRC cycle SCE's proposal to allocate any generation capital costs to flexible capacity needs should be rejected		Based on the generation functional allocators shown in Table RA-3, subject to collaring

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
	TOU sales in each rate class, where the TOU sales are grouped in the proposed TOU periods Generation Capacity MCRR - Determined by multiplying marginal capacity costs by the forecasted peak and ramp MWs attributable to each rate class	1 hour or peaking capacity Concerning flexible capacity cost drivers, proposes allocation of the DG component should be on the basis of each class' share of system-level annual sales consistent with SCE's proposed treatment of the RPS component	MCRR calculation.				this proceeding Disagree with Cal Advocates' proposal to treat peak and ramping as a joint cost driver					
Distribution Revenues	Peak: PLRF Grid: NCP x EDF x Cost Customer: MC x Forecasted Customers Non-allocated revenues specifically assigned to street lights of $88,511,383	Adopt Cal Advocates' proposed MDDC regression method (see DDMC below) and grid/peak split	Use subtransmission and distribution scalars to increase the costs per kW so that they are consistent with the marginal demand measures	Recommend to reject SCE's bifurcation of distribution and require that SCE treat all distribution as load related, using the PLRF method						Per proposed MC based allocations and agricultural load forecast revision in AECA testimony		Based on the distribution functional allocators shown in Table RA-3, subject to collaring Adjustment made for Ag & Pumping related to NCP demands to use a 7-yr average to account for broader range of potential hydrological conditions

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
												consistent with the 2018 GRC Phase 2 Settlement Agreement Non-allocated revenues assigned directly to street light of $77,869,691 w/ recovery addressed in rate design phase of proceeding
Wildfire Allocation	Proposes to allocate cost based on underlying nature and purpose of the cost. 1. Utility distribution infrastructure costs subject to PU Code § 8386(e) – Distribution allocator 2. Wildfire claims in excess of insurance - A&G labor allocator 3. Insurance premium – A&G labor allocator 4. Undercollection amount from res and	Require SCE to allocate wildfire mitigation Capex and related O&M expenses, wildfire liability insurance claims, and wildfire liability insurance premiums equitably based on an equal cents per kWh allocation through PPP charge Rejects SCE's request to modify CARE/FERA allocation to recover	Supports Cal Advocates' proposal		Supports SCE's proposal to allocate wildfire mitigation cost Proposes that RUBA and uncollectibles should be collected from non-CARE/FERA members of the residential and small commercial class and not in the PPP	Supports SCE's proposal to allocate wildfire mitigation cost For wildfire liability claims and insurance premiums, the use of an A&G allocator limited to distribution would be more refined, since wildfires are more associated with distribution than with generation	Do not object to SCE's proposal	Cal Advocates' recommendations should be rejected				The WRR shall be recovered through distribution rates and shall be allocated using the formulaic approach

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
	small commercial bad debt – ERRA related in generation and non-ERRA in PPP rates	shortfall associated with CARE/FERA exemption from FRC Adopt SCE's proposal to exempt CARE/FERA customers from res/small commercial bad debt				or transmission Agree to SCE's proposal of the use of demand charge in the FRC for securitized wildfire cost						
TE Allocation	Establish allocation protocol 1.Utility-side-of-the-meter infrastructure cost (Distribution) 2. Customer side-of-the-meter infrastructure cost: (Allocation based on participation) 3. Others – General non-functional costs and rebate – (SAP), Marketing Cost – (Distribution)	Cal Advocates proposes that TE program costs should be allocated on the basis of system sales (equal cents per kWh allocation)	Supports Cal Advocates' proposal that TE program should be allocated on an equal-cents-per-kWh basis Allocate $14M of EV pilot programs using the PPP allocation factor		Supports SCE's proposal to allocate TE cost	Generally agrees with SCE's proposed approach	SCE's proposal is reasonable					Allocation and recovery of TE related revenue requirements attributable to the four programs will maintain the allocation and recovery methods directed in each program's respective decision Any future TE program application will be subject to the cost allocation authorization made in the proceeding that authorizes the program and

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
												associated funding
Public Purpose Programs	Assign revenues to rate groups on a system average percentage w/ generation revenues imputed for DA/CCA The CARE balancing account revenues are allocated to the other non-exempt rate groups based on each group's share of total annual energy sales (excluding the exempt groups)				Supports SCE proposal							Allocate based on each rate group's percentage share of system revenues for bundled service and DA/CCA customers, with generation revenues imputed for DA/CCA CARE discount allocated to rate groups on an equal cents per kWh basis, but excluding the kWh usage of CARE and street light customers CARE Balancing Account/CARE Admin shall be allocated based on each rate groups percentage of revenues as stated above for PPP allocation, excluding CARE and

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
												Streetlight revenues
Self-Generation Incentive Program	Consistent with D.18-11-027, allocate SGIP revenues based on the proportion of SGIP incentives disbursed to different rate groups over the most recent three years.				Supports SCE proposal							Allocation is based on the proportion of incentives disbursed to each rate group over the most recent three years; update the allocation on a rolling basis annually
Tree Mortality Non-bypassable Charge	Set on a cent-per-kWh basis and added to PPP. Allocated using the 12-month CP allocator as adopted in D.18-12-003				Supports SCE proposal							Set on a cent-per-kWh basis and added to PPP. Allocated using the 12-month CP allocator as adopted in D.18-12-003
Nuclear Decommissioning	Allocated on an equal cents / kWh basis to rate groups for all retail customers											Allocated on an equal cents / kWh basis to rate groups for all retail customers
Demand Response	Interruptible Programs – recovered from all rate groups in distribution rates; allocated to rate groups based on the marginal cost of generation methodology		Use EPMC generation w/ gen imputed for DA/CCA									Interruptible program costs shall be allocated to rate groups for recovery in distribution rates based on the system generation allocators DR rev req 50% of DR rev

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
												req will be allocated be each rate group's proportional share of system revenues, with generation revenues for DA/CCA customers imputed as bundled customers and the remaining 50% will be allocated by uncollared distribution allocators
Energy Efficiency	Allocate $10.7M EE shareholder incentives using distribution allocator		Allocate $11M EE shareholde r incentives using PPPC allocator w/ gen imputed for DA/CCA									Allocate EE shareholder incentives using distribution allocator where applicable (rev req at $0 in October 2021)
CIA	Eliminate tracking of the CIA balances as a separate amount recorded in PPPAM that is only recovered from residential											Eliminate tracking of the CIA balances as a separate amount recorded in PPPAM that is only recovered from residential

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
	customers. Instead, SCE would recover the amount from all customers											customers. Instead, SCE would recover the amount from all customers
Non-Allocated Streetlight (SL) Revenue Requirement	Set the non-allocated revenue requirement at $88.511 million for 2021, derived using the Results of Operations Model in SCE's GRC Phase 1, and is based on the forecast FERC Account 373 Rate Base and O&M expenses attributable to streetlight										The LS-1 Option E Energy Efficient Premium Charges revenue deduction should be removed from the streetlight non-allocated revenue requirement	Use a non-allocated rev req of $77,870,000

Marginal Costs

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	SEIA	Settled Position
GCMCs ($/kW-yr. w/o RA adder)	$79 Forecast for the NetCONE of a 4-hour lithium-ion battery proxy resource, net of energy rents based upon 2024	$63.19, reflects the timing of need of new capacity over the next six years and updates SCE's outdated battery costs with more accurate, recent battery cost figures	$54.78 Proposes a six-year calculation of capacity cost forecasts Incorporates Cal Advocates' reduction based on expected battery cost declines Reduced Fixed O&M, Warranty, and Battery Augmentation, as well as other financial assumptions and modeling	Generally agrees with the use of 4-hour battery storage as the cost basis for GCMCs	$173 Updated battery cost assumption, calculated long run project of each 2021-2024 build year and then levelized the marginal cost for 2021-2024, battery contract assumption changed to 15 years, 1.25% property tax, and replaced financing costs with CLECA recommendation. Corrected SCE's annualization and discounting of offsetting energy rents.	$192 Proposes levelized cost of photovoltaic generation be added to SCE's energy storage GCMC value Disagree with SCE's approach to deduct energy rent	$192 Proposes levelized cost of photovoltaic generation be added to SCE's energy storage GCMC value Disagree with SCE's approach to deduct energy rent		Supports Cal Advocate GCMC Value: $63.19 Agrees with using 4-hour lithium-ion battery as the basis for GCMC, but update its cost assumption to rely on more recent cost data	$73 Use the RA value from the PCIA MPB to put bundled and departed customers on a comparable basis for allocation.	$138 Proposes to use battery storage costs over the 2022-2024 period	$100
Peak / Flex Split of GCMCs	Peak/ Flex MCRR ratio 65%/35%, ratio Allocation of peak capacity costs is based on the relevant	Allocates 25% cost to peak and 75% to flex to reflect a 4-hour lithium battery would		Recommends all costs be allocated to peak capacity as	Agrees with SCE that the peak requirement for generation capacity is	Disagree with Cal Advocates' proposal to treat peak and ramping as	Disagree with Cal Advocates' proposal to treat peak and ramping as		Opposed Cal Advocates' proposal to use a "shared cost" model	Recommends all costs be allocated to peak capacity as proposed by PG&E		SCE's Capacity Allocation Tool to spread the GCMC across TOU periods

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	SEIA	Settled Position
	top 100 hours of net loads. Allocation of flexible capacity cost is based on the relevant top 10 maximum daily 3-hour change in net load	theoretically provide 3 hours of ramping capacity and 1 hour or peaking capacity		proposed by PG&E	separate from ramp requirement, separate cost not a joint cost.	a joint cost driver	a joint cost driver					and that it be partly allocated based on peak demand and partly based on the need for ramping capacity
MECs (¢/kWh)	Summer: On – 3.53 Mid – 3.28 Off – 2.74 Winter: Mid – 3.49 Off – 3.56 SOff – 1.42 Derived using production simulation model (PLEXOS)			Summer: On – 3.72 Mid – 3.50 Off – 2.66 Winter: Mid – 3.54 Off – 3.27 SOff – 1.64 Recommends that SCE recalculates its MEC using PG&E's method	Recommends using 2021-2024 average for MECs							Summer: On – 4.19 Mid – 3.84 Off – 3.33 Winter: Mid – 3.86 Off – 3.91 SOff – 2.05
Customer MC Method	SCE's RECC	Cal Advocates' NCO Actual new connection used to calculate growth rate, uniform growth rate for all nonresidential customers, includes a replacement cost adder and exclude uncollectible	TURN's NCO Use SCE's method of calculating changes in net customers but develops replacement rates for each customer class that are based on reality, separate growth rate for each class, does not oppose to Cal	Recommends the Commission to adopt Cal Advocates' proposal for MCAC and apply EPMC scaled costs to the volumetric distribution rates Recommend Commissio	SCE's RECC	SCE's RECC	SCE's RECC	SCE's RECC Commission should direct SCE to conduct an embedded cost of service analysis for customer access cost and present in	SCE's NCO Disagree w/ Cal Advocates' customer growth proxy	Recommends RECC costs for new connections and RCNLD for existing connections best captures opportunity cost for setting marginal cost		50:50 ratio of SCE's RECC and TURN's NCO marginal customer costs calculations.

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	SEIA	Settled Position
			Advocates' recommendation to include metering costs as an adder	n to direct SCE to perform an embedded cost study for its next GRC				next GRC Phase 2				
DDMCs ($/kW-yr.)	$181, computed using the incremental cost of adding capacity from the NERA regression method; functionalized into *peak* and *grid*, and into asset *type* (substations and circuits) and asset *category* (dist and subtrans); use PLRF method as basis of assigning a time-sensitive allocation of peak capacity-related costs and EDF method for grid-related costs	$285. Proposes to use rolling maximum regional load approach, instead of planned capacity, as the independent variable in the NERA regression Uses historic recorded load in its NERA regression	$558. Believes there is a mismatch between demand kW used to calculate costs and much lower demand used to allocate costs, so propose the use of scalars to fix the problem of disappearing MW	Suggests using Cal Advocates' rolling maximum load approach, but rather using the load in each year forecasted two years earlier, rather than the load in the year	Supports SCE's regression approach Makes an adjustment to account for the difference in the projection of peak demand used in the marginal cost analysis Recommends Commission to direct SCE to organize working group to study appropriate costs basis for determining MDCC for next GRC		Supports SCE's proposal to use planned growth for the development of the estimate of DDMC	Believes SCE's used of planned capacity to be more appropriate than Cal Advocates' proposed rolling maximum of historic demand method				For purposes of revenue allocation, marginal distribution costs shall be consistent with SCE's proposal SCE and interested parties have agreed to engage in discussions to explore derivation of design demand marginal cost and refinement to the peak/grid split for incorporation in SCE's next GRC Phase 2 proceeding
Peak / Grid Split of DDMCs	$83.7 Peak (46%) / $97.3 Grid (54%)	$172.4 Peak (60%) / $113 Grid ("Non-Peak") (40%)	All subtrans costs should be peak but at minimum Cal	Reject SCE's bifurcation of	Supports SCE's refinement on					$83.7 Peak (46%) / $97.3 Grid		See DDMC above

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	SEIA	Settled Position
		All distribution circuit lines defined as backties be functionalized as peak costs Recommends a 50/50 split in the grid and peak costs of sub transmission circuits	Advocates' proposed 50/50 design/peak method should be used; support Cal Advocates' proposal over SCE's for dist circuits If SCE's method is used, split should be 37.2% peak / 62.0% grid	distribution and require that SCE treat all distribution as load related	estimating portion of MDCC between peak/grid Recommends Commission to direct SCE to conduct a study that breaks apart the cost of subtransmission circuit addition between load growth/reliability					(54%) per SCE		
Sales Forecast	Use kWh sales forecast for 2021 as the basis for the billing determinant forecast and rate design proposals, as filed in A.19-08-013									Agricultural load forecast should be revised to more accurately represent the dominate role variations in water supply availability play in shaping agricultural load, as well as including economic activity in the sector		Use SCE's 2021 sales forecast as of October 1, 2021
Bundled - DA/CCA split	Assume a flat 55% for all classes				Impute split for each customer							Step 1: Derived a 2024 Net

Issue	SCE	Cal Advocates	TURN	SBUA	CLECA	EPUC	FEA	DACC	CFBF	AECA	SEIA	Settled Position
					class based on SCE's sales forecast and maximum demand forecast							Load at the Retail Level, broken out by customer group Step 2: Using actual consumption (2019/2020) at bundled level, SCE layered on 2024 Forecast DERs scaled to each customer group's bundled-to-retail sales % Step 3: Determined each customer group's contribution to capacity constraints

Appendix B

Illustrative Rates Using Revenue Allocation Inputs From Settlement Agreement

Table B-1
Bundled Service Rate Groups (without California Climate Credit and EITE Credits)
Illustrative Rates[1]

	October 2021	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	25.4	25.3	25.4	-0.5%	0.0%	115%	115%
GS-1	23.8	21.6	23.5	-9.2%	-1.6%	108%	106%
TC-1	26.6	20.8	26.6	-21.7%	0.0%	121%	121%
GS-2	24.0	24.2	23.7	0.8%	-1.5%	109%	107%
TOU-GS-3	21.3	21.6	21.7	1.2%	1.5%	97%	98%
Total LSMP	23.4	22.9	23.2	-1.9%	-0.9%	106%	105%
TOU-8-Sec	18.5	18.5	18.6	0.1%	0.5%	84%	84%
TOU-8-Pri	16.7	17.6	16.9	5.8%	1.5%	75%	77%
TOU-8-Sub	11.2	11.8	11.3	5.7%	1.5%	51%	51%
Total Large Power	16.0	16.5	16.2	2.8%	1.0%	73%	73%
TOU-PA-2	20.1	19.2	19.8	-4.8%	-1.6%	91%	90%
TOU-PA-3	16.9	17.8	17.2	5.3%	1.5%	77%	78%
Total Ag.&Pumping	18.7	18.6	18.6	-0.8%	-0.4%	85%	85%
Total Street Lighting	24.6	28.3	24.9	15.0%	1.3%	111%	113%
STANDBY/SEC	18.2	18.3	18.2	0.7%	0.2%	82%	83%
STANDBY/PRI	18.8	18.6	18.7	-0.8%	-0.5%	85%	85%
STANDBY/SUB	11.3	12.4	11.4	9.5%	1.3%	51%	52%
Total Standby	13.0	13.8	13.1	6.2%	0.7%	59%	59%
Total System	22.1	22.1	22.1	-0.2%	-0.1%	100%	100%

[1]Excludes Climate Dividend and EITE Credits

Table B-2
Direct Access Groups
Direct Access/CCA Rate Groups (without California Climate Credit and EITE Credits)[1]
Illustrative Rates

	October 2021	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	19.0	18.3	18.6	-3.4%	-1.9%	140%	137%
GS-1	16.2	16.1	16.4	-0.5%	1.0%	120%	120%
TC-1	20.6	14.5	20.1	-29.5%	-2.3%	152%	148%
GS-2	15.0	16.0	15.3	6.7%	1.8%	111%	113%
TOU-GS-3	12.6	12.8	12.8	1.2%	1.7%	93%	95%
Total LSMP	14.4	14.9	14.6	3.7%	1.6%	106%	107%
TOU-8-Sec	11.7	11.7	11.9	0.3%	1.5%	86%	87%
TOU-8-Pri	10.2	10.6	10.4	4.1%	2.1%	76%	77%
TOU-8-Sub	5.2	5.4	5.4	3.1%	3.2%	39%	40%
Total Large Power	8.9	9.1	9.1	2.1%	2.1%	66%	67%
TOU-PA-2	14.1	13.6	13.9	-3.5%	-1.6%	104%	102%
TOU-PA-3	11.3	11.3	11.4	0.2%	1.3%	83%	84%
Total Ag.&Pumping	12.7	12.5	12.7	-1.9%	-0.3%	94%	94%
Total Street Lighting	24.6	25.0	25.1	1.9%	2.1%	182%	185%
STANDBY/SEC	12.4	12.2	12.2	-2.0%	-1.8%	92%	90%
STANDBY/PRI	11.1	11.0	11.1	-1.3%	0.0%	82%	82%
STANDBY/SUB	6.2	6.5	6.4	5.7%	4.2%	46%	47%
Total Standby	7.9	8.1	8.0	2.3%	2.0%	58%	59%
Total System	13.5	13.6	13.6	0.6%	0.4%	100%	100%

[1] Excludes Climate Dividends, and EITE Credits

Table B-3
Proposed Bundled Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	Generation	Total Bundled
Total Domestic	402.6	2,083.9	629.8	3,116.2	1,977.8	5,094.0
GS-1	64.9	370.8	136.6	572.3	363.1	935.4
TC-1	0.5	5.9	1.2	7.6	3.1	10.7
GS-2	126.5	787.9	259.8	1,174.2	625.5	1,799.7
TOU-GS-3	56.9	301.2	116.7	474.7	278.6	753.2
Total LSMP	248.8	1,465.7	514.3	2,228.7	1,270.2	3,499.0
TOU-8-Sec	58.3	266.4	127.7	452.4	295.6	748.0
TOU-8-Pri	32.3	133.7	74.1	240.0	170.1	410.1
TOU-8-Sub	27.2	24.2	62.9	114.3	153.4	267.6
Total Large Power	117.8	424.2	264.6	806.7	619.0	1,425.7
TOU-PA-2	16.4	105.1	44.1	165.5	109.4	274.9
TOU-PA-3	12.9	65.9	34.6	113.4	74.4	187.8
Total Ag.&Pumping	29.3	171.0	78.6	278.9	183.8	462.7
Total Street Lighting	3.7	61.0	6.5	71.3	21.4	92.7
STANDBY/SEC	2.1	9.1	4.5	15.8	11.0	26.8
STANDBY/PRI	6.3	31.3	15.0	52.7	33.8	86.5
STANDBY/SUB	23.2	32.4	55.5	111.1	124.5	235.6
Total Standby	31.7	72.8	75.1	179.6	169.3	348.9
Total System	**833.8**	**4,278.6**	**1,568.9**	**6,681.4**	**4,241.6**	**10,923.0**

Includes NSGS in "Other" Category

Table B-4
Proposed DA/CCA Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	PCIA, CTC, DWRPC	Total DA
Total Domestic	142.8	886.8	87.9	1,117.5	205.9	1,323.3
GS-1	23.8	163.6	20.2	207.5	31.1	238.6
TC-1	0.2	2.4	0.2	2.8	0.3	3.1
GS-2	67.6	491.2	64.4	623.2	79.0	702.2
TOU-GS-3	44.8	295.3	46.6	386.6	38.0	424.6
Total LSMP	136.3	952.5	131.4	1,220.2	148.3	1,368.5
TOU-8-Sec	45.7	273.4	44.7	363.8	43.6	407.4
TOU-8-Pri	31.5	182.0	32.9	246.4	23.9	270.3
TOU-8-Sub	39.6	98.6	35.6	173.7	17.8	191.5
Total Large Power	116.8	553.9	113.1	783.9	85.3	869.2
TOU-PA-2	4.4	34.3	5.4	44.2	7.3	51.4
TOU-PA-3	3.7	24.7	5.1	33.5	6.0	39.4
Total Ag.&Pumping	8.1	59.1	10.5	77.7	13.2	90.9
Total Street Lighting	1.7	36.6	2.0	40.3	3.0	43.3
STANDBY/SEC	0.6	3.2	0.4	4.2	0.2	4.4
STANDBY/PRI	1.9	12.7	2.4	17.0	1.2	18.2
STANDBY/SUB	4.5	14.9	4.2	23.6	2.5	26.1
Total Standby	6.9	30.8	7.0	44.8	3.9	48.7
Total System	**412.6**	**2,519.7**	**352.0**	**3,284.3**	**459.7**	**3,744.0**