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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.17-06-030 (Filed June 30, 2017)

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

FADIA R. KHOURY
RUSSELL A. ARCHER

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
Facsimile: (626) 302-3990
E-mail: Russell.Archer@sce.com

Dated: **July 13, 2018**

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

Table of Contents

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I.

INTRODUCTION

Pursuant to Rule 12.1 *et seq*. of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, Southern California Edison Company (SCE), on behalf of itself and the Settling Parties,[1] files this Amended Motion that requests the Commission find reasonable and adopt the "Revenue Allocation Settlement Agreement" (Settlement Agreement or Agreement), which is appended to this Motion as Attachment A. This Amended Motion replaces the original Motion for Adoption of Revenue Allocation Settlement Agreement filed on July 3, 2018.[2]

1 The Settling Parties or Parties are SCE; The Utility Reform Network (TURN); Small Business Utility Advocates (SBUA); the Office of Ratepayer Advocates (ORA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); 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); California City-County Street Light Association (CAL-SLA); 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 Agreement: Solar Energy Industries Association (SEIA) and Coalition for Affordable Street Lights (CASL).

2 As set forth in the Conclusion below, this Amended Motion seeks the withdrawal of the original Motion.

The Settling Parties have executed the Settlement Agreement that resolves all issues that have been raised with respect to revenue allocation in this proceeding. For purposes of determining the revenue allocation for settlement purposes only, the Parties agreed to a set of marginal cost inputs that fell within the proposals made by the various parties in their opening testimony, which were then moderated by agreed-upon "collaring" and "capping" parameters. While any settlement agreement should be analyzed by the Commission as a "package deal" and not as a series of individual provisions, that is especially true for this Revenue Allocation Settlement Agreement. No Party specifically endorses any of the individual marginal cost components that collectively produce the overall revenue allocations to customer groups standing alone; rather it is the collective combination of those individual components (after applying the mitigating and muting effects of collaring and capping) that produces an overall revenue allocation that the Settling Parties agree is reasonable. Accordingly, the individual marginal cost components must be viewed solely for what they are: settlement compromise building blocks for an overarching revenue allocation edifice that all Parties agree is ultimately reasonable.

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 January 1, 2019, 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 regulatory 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.

REGULATORY BACKGROUND

A. Background of this Proceeding

This proceeding was initiated by the filing of SCE's application on June 30, 2017, along with service of SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design. On November 22, 2017, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a November 2, 2017 prehearing conference. ORA served its initial testimony on February 16, 2018. On March 23, 2018, the following Settling Parties submitted prepared testimony regarding marginal cost or revenue allocation: SBUA, TURN, AECA, EUF, CLECA, EPUC, FEA, CFBF, SEIA, and DACC.[3]

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.

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 April 6, 2018. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference.

III.

SUMMARY OF POSITIONS AND SETTLEMENT

The Settlement Agreement resolves all issues related to revenue allocation in this proceeding (with necessary marginal cost input proxies). Its primary provisions are summarized below and in a comparison exhibit, Appendix A to the Settlement Agreement. Both this Motion and the comparison

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[3] SBUA submitted its prepared testimony on March 21, 2018.

exhibit provide a comparison of party positions related to the relevant issues and the manner in which these issues have been resolved by the Settlement Agreement.[4]

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

- Marginal customer, distribution demand, generation capacity, and generation energy cost components;
- Allocation of functional distribution and generation unbundled revenue requirements based on marginal cost components or in accord with prior Commission decisions; and
- Capping (or "collaring" as defined in the Agreement) 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. 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 calculation 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 their 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. Those individual marginal cost proposals varied substantially, as set forth below and in the comparison exhibit. For purposes of settlement, however, marginal costs that were used to create the revenue allocation settlement set forth in the Settlement Agreement fell within

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

the bounds defined by the various marginal cost proposals made by the Parties, and the Settling Parties agree that, solely for the specific purpose of this Revenue Allocation Settlement Agreement and for that purpose only, they are reasonable. These settled marginal costs are not intended by the Settling Parties to be used for any other purposes outside of this proceeding. Indeed, different marginal cost values may be used for rate design settlements and/or litigation within the bounds of the instant proceeding.

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. The Parties' initial litigation positions on revenue allocation are summarized below.

Summary of Initial Positions on Revenue Allocation

Bundled Service:	**SCE**	**ORA[1]**	**SBUA**	**TURN[2]**	**CLECA**	**EPUC**	**FEA**	**CFBF**	**AECA[3]**	**DACC[4]**	**Settlement**
Residential	4.1%	-1.5%	1.6%	-0.4%	4.5%	8.3%	5.7%	3.5%			-1.72%
TOU-GS-1	-6.3%	-3.5%	-9.6%	-3.2%	-6.5%	-7.5%	-6.9%	-7.5%			-4.22%
TC-1	-0.1%	0.3%	2.3%	0.0%	-0.4%	-3.5%	-1.5%	-9.1%			-3.29%
TOU-GS-2	-5.8%	-2.8%		-3.2%	-5.9%	-8.6%	-6.4%	-6.0%			-4.21%
TOU-GS-3	-3.8%	1.6%	-4.5%	2.8%	-4.1%	-7.7%	-4.9%	-2.2%			-4.21%
Total LSMP	-5.5%	-1.9%			-5.6%	-8.1%	-6.1%				-4.21%
TOU-8-Sec	-2.7%	1.6%	1.4%	2.8%	-3.1%	-7.0%	-4.3%	-0.8%			-3.53%
TOU-8-Pri	-0.5%	1.6%	1.6%	2.8%	-1.0%	-4.4%	-2.3%	1.6%			-3.53%
TOU-8-Sub	3.1%	1.6%	2.3%	2.8%	2.3%	-3.3%	0.1%	3.5%			-3.53%
Total Large Power	-0.9%	1.6%			-1.4%	-5.5%	-2.9%				-3.53%
TOU-PA-2	2.8%	1.6%	0.7%	2.8%	2.3%	-1.3%	1.1%	0.1%			-4.22%
TOU-PA-3	7.3%	1.6%	0.9%	2.8%	6.8%	3.1%	5.2%	6.7%			-1.89%
Total Ag&Pump	4.5%	1.6%			4.9%	0.3%	2.6%				-3.29%
Street Lighting	6.0%	1.6%	1.7%	2.8%	-	7.9%	1.9%	6.2%			-1.72%
Standby-Sec	-0.6%	1.6%	1.5%	2.8%	-1.1%	-4.9%	-2.5%	1.3%			-4.21%
Standby-Pri	-0.9%	1.6%	0.0%	2.8%	-1.3%	-4.2%	-2.6%	1.2%			-4.22%
Standby-Sub	5.2%	1.6%	4.8%	2.8%	4.3%	-1.3%	1.7%	5.2%			-4.22%
Total Standby	2.9%	1.6%			2.2%	-2.5%	0.0%				-4.22%
Total System	0.0%	-0.9%		-0.2%	0.0%	0.0%	0.0%				-2.97%

[1]Showing ORA's capped rates; use own marginal costs and adjusted sales forecast.
[2]Showing TURN's capped rates; use own marginal costs.
[3]Revenue allocations should be frozen.
[4]SCE's proposed method for allocating distribution rev req is superior to ORA; RECC should be used.

As set forth in more detail below and in the comparison exhibit, the Parties also disputed whether the Commission should "cap" or limit the amount of SCE's revenue requirement that is allocated to any rate group, and, if so, the level of the cap and 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. Ultimately, for purposes of this Settlement Agreement only, the Parties agreed to "cap" or "collar" the marginal costs so as to limit the rate impacts on any particular rate group. In addition, and as further explained in the Settlement Agreement, the Parties agreed that it was reasonable to allocate certain marginal costs to specific "peak," "grid," and "ramp" functions, in recognition of the increasing importance of those various characteristics for the modern electrical system.

In order to avoid further 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 SCE's Model). SCE's total revenue requirement adopted in this Settlement Agreement will take effect after the Commission issues a decision adopting the Settlement Agreement. 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 also had to determine an estimated revenue requirement and an estimated sales forecast. Importantly, over the course of the settlement negotiations, SCE's estimated future revenue requirement and sales forecast for future years changed significantly from the assumptions used by the Parties when developing their litigation positions, due to the following three important factors: (1) ongoing uncertainty about current ongoing SCE revenue-requirement-related regulatory proceeding results and timing outcomes (*e.g.*, SCE's pending 2018 GRC Phase 1); (2) significant federal tax law reform; and (3) material increases in the amount of departing load (and therefore decreased bundled service customer sales) due to CCA formation.

As set forth in Section 4.B.1 and in Appendix C of the Settlement Agreement, the Settling Parties decided that it was reasonable to adopt an estimated consolidated revenue requirement that incorporated realistic assumptions regarding those three important factors. Specifically, the Settling Parties agreed on an estimated consolidated revenue requirement of $11,420 million, including revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the California Solar Initiative, the DWR Bond Charge, the New System Generation Charge, and greenhouse gas (GHG) costs and allowances (excluding the California Climate Credits and the revenue return to Emission-Intensive and Trade-Exposed (EITE) customers). The illustrative rates provided in Appendix B of the Settlement Agreement—which are based on the estimated consolidated revenue requirement—will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the Settlement Agreement when rates are first implemented.

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 estimated consolidated revenue requirement, resulting in a bundled service system average percentage change from the January 2018 rate level of 16.7¢/kWh to an estimated 2019 rate level of 16.2¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's April 2018 ERRA Forecast direct testimony for forecasted sales for 2019, as illustrated in Table B-1 of the Settlement Agreement (and reproduced below).[5] To promote rate stability and to limit bill impacts to individual customers groups and classes, 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-2 and

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

Paragraph 4.B.2 of the Settlement Agreement (*i.e.*, "collaring"). Specifically, distribution rates were "collared" between a "cap" of the System Average Rate (SAR) plus 2.5% and a "floor" of the SAR minus 2.5%. Similarly, generation rates were "collared" between a "cap" of the SAR plus 1.25% and a "floor" of the SAR minus 1.25%. "Collaring" provides customers with reasonable certainty and stability, which is an important principle of Commission rate design.

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, DWR bond 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 i.

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 GRC proceeding is implemented shall be allocated pursuant to the functional character of the revenue requirement change on an SAPC basis. This is consistent with how previous GRC Phase 2 rates have been implemented, and is reasonable.

IV.

REQUEST FOR ADOPTION OF THE SETTLEMENT AGREEMENT

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.[6] 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.[7] As long as a settlement taken as a

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[6] *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).

[7] D.92-12-019, 46 CPUC 2d 538, 553.

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.[8]

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. The Settling Parties request that the Commission admit the prepared testimony and related exhibits into the Commission's record of this proceeding.

The Settlement Agreement represents a reasonable compromise of the Settling Parties' positions. The Settling Parties put forth various proposals that each party believed were supported by Commission precedent, appropriate public policy goals, and/or Commission rate design guidance. The Settling Parties then negotiated extensively at arms' length on the merits of those various proposals. The prepared testimony of the Settling Parties; this Motion; the body of the Settlement Agreement; as well as Exhibits A (comparison exhibit), B (illustrative rates) and C (amended revenue allocation table reflecting the three major changes discussed above) to the Settlement Agreement collectively contain sufficient information for the Commission to judge the reasonableness of the Settlement. In summary, the Settlement Agreement overall, as a package, is a reasonable resolution, and represents compromises within the range of parties' various good faith litigation positions, on the following subject areas. As

[8] *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360.

noted above, while each individual marginal cost sub-component is reasonable for purposes of this Settlement Agreement, and was the subject of good-faith, arms-length negotiations, none can be analyzed in isolation. Rather, it is only the resulting overall revenue allocation to customer groups (and the resulting rate impacts) that is appropriate for – and for which the Settling Parties are seeking – a Commission determination of overall reasonableness. The Commission explicitly recognized this principle in resolving SCE's last GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement: "Thus, 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 designated marginal costs set forth in … 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 … ."[9]

1. Marginal Generation Capacity Costs (MGCCs)

The parties advocated for different values of marginal generation capacity. Specifically, the Settling Parties' litigation positions varied from proposed MGCC of $57.92/kW-year to $215/kW-year. These figures would have been modified had the impact of the federal tax law changes been incorporated. Ultimately, the Settling Parties compromised on a MGCC value, which is within the range of the parties' litigation positions, and a number that they agreed is only reasonable for purposes of the Settlement Agreement.

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) that ranged from a 61%/39% split between "peak" and "flex" capacity (SCE) to a 31%/69% split between "peak" and "flex" capacity (ORA). Ultimately, the Settling Parties agreed to a compromise peak/flex split which they believe to be reasonable for purposes of the Settlement Agreement only, which is within the range of the parties' litigation positions. Parties further agreed that this split requires additional analysis and data and SCE agreed to engage in discussions to explore

9 *See, e.g.*, D.16-03-030 at p. 12.

potential future refinements to the peak/flex generation capacity split for incorporation in SCE's next GRC Phase 2 proceeding.

2. Marginal Energy Costs (MECs)

The Settling Parties initially advocated for different values of marginal energy costs, but ultimately agreed that updating those costs for more recent projections of natural gas prices and GHG allowance costs was necessary and reasonable. For the purposes of this revenue allocation settlement, the Parties also agreed to a set of marginal energy costs that vary by season and TOU periods based on these updates, which is appropriate.

3. Customer Marginal Costs Methods

Various parties including SCE, ORA and TURN advocated for different customer-specific marginal costs, based on different methodologies that have been debated in previous Phase 2 proceedings, i.e. a Real Economic Carrying Cost (RECC) methodology and a New Customer Only (NCO) methodology, both of which received support from several parties. For purposes of revenue allocation only, marginal customer costs for purposes of the Settlement Agreement only were determined based on a compromise between these two methodologies. Previous SCE GRC Phase 2 settlements approved by the Commission have incorporated a "blend" between the two methodologies.[10] This is a reasonable resolution of an issue to avoid litigation risk and to reach a broader settlement on revenue allocation issues.[11]

For the avoidance of doubt, this settled marginal customer cost value and methodology is to be used solely for purposes of the Settlement Agreement. SCE shall not use the settled value or methodology in the Settlement Agreement, or any Commission decision approving all or part of it, as evidence (including as an exhibit) in any future Commission proceeding, including but not limited to

[10] *See, e.g.*, D.16-03-030 at p. 12 (approving SCE's 2015 GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement, which generally incorporated the same 50:50 ratio used here).

[11] *See, e.g.*, *id.* ("Thus, 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 designated marginal costs set forth in … 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 … .").

proceedings considering the reasonableness of residential fixed charges.

4. Distribution Design Demand Marginal Costs (DDMCs)

The parties advocated for different values of distribution design demand capacity based on different marginal cost methodologies. They also advocated for significantly different methods to functionalize DDMCs between "grid" and "peak categories, where grid represents a network-type function and peak represents meeting customers' peak loads. Ultimately, the Settling Parties compromised on a DDMC value within the range of the parties' litigation positions, which the parties agree is reasonable for these settlement purposes only. The Settlement Agreement also allocates the total distribution marginal capacity partly to "peak" and partly to "grid" functions on the basis of a compromise on the functionalization methodologies. Parties generally agreed that this conceptual differentiation needs more analysis in the future and SCE agreed to provide additional information regarding the peak/grid distribution capacity split in SCE's next GRC Phase 2 proceeding, as requested by ORA.[12]

5. Sales Forecast

The sales forecast embodied in the Settlement Agreement was developed using SCE's May 2018 ERRA Forecast application (and supporting direct testimony therefrom), which represents SCE's then-current estimate of departing load for 2019.

6. "Capping"/"Collaring"

SCE did not initially propose to "cap" or impose "collars" on any rate changes resulting from this proceeding. Most of the other parties did, however, at various levels, and for different rates. Ultimately, the Settlement Agreement implements capping and collaring to different rates as follows: +/- 2.5% for delivery rates; +/- 1.25% for generation rates; a 2% secondary delivery cap for TOU-GS-3 rates; and a -3.5% floor for non-Standby TOU-8 rates. This negotiated compromise promotes rate certainty and stability for all rate groups and ensures that no particular rate group is disproportionately

[12] Specifically, as requested in testimony submitted by ORA, SCE agrees to provide its distribution demand investment, nameplate capacity and load data at the regional level, and at the substation level, and to produce a load-weighted average distribution design marginal cost at each level of the system.

benefitted or burdened by the overall settlement revenue allocation levels.

7. Other Issues

Within one year of the adoption of this Agreement, SCE and interested parties have agreed to create a working group to discuss how to incorporate a flexible generation capacity component into the revenue allocation process in addition to a peak capacity component. The focus will be on how generation capacity marginal costs should be split between peak and flexible capacity in the future. 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 2021 GRC Phase 2 Application (and serves its supporting testimony).

B. The Settlement Agreement is Consistent with the Law

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 explicitly 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. The Settlement Agreement Is in the Public Interest

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 interest of SCE's customers. The Parties to the Agreement fairly represent the interests of the wide variety of customers and customer classes that are affected by the revenue allocation. It 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 other parties, so that they may focus on other proceedings and the rate design portions of this proceeding. The prepared direct testimony, this Motion, and the Settlement Agreement itself (and exhibits thereto) contain sufficient information for the Commission to judge the reasonableness of the Settlement Agreement and for it 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 and Each Provision is Dependent on the Others and the Final Revenue Allocation Results</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, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

V.

PROPOSED SCHEDULE FOR COMMENTS AND IMPLEMENTATION OF SETTLEMENT AGREEMENT

The Settling Parties seek approval of the terms of the Settlement Agreement so that SCE may implement rates as soon as practicable following the issuance of a final Commission decision approving the Settlement Agreement but no earlier than January 1, 2019. In order to accomplish this, the Settling Parties recommend the following the time periods provided by Rule 12.2 for comments and replies to comments on the Settlement Agreement. In order to accommodate questions about the Settlement Agreement, in the event that there are material contested issues of fact, or questions from the Commission, the Settling Parties request that a portion of one day be scheduled for a hearing (with a panel of sponsoring witnesses) in accordance with the following schedule.

Event	**Date**
Amended Motion filed for Adoption of the Settlement Agreement	July 13, 2018
Opening comments, if any, on the Settlement Agreement	August 13, 2018
Reply comments, if any, on the Settlement Agreement	August 28, 2018
Hearing on the Settlement Agreement, if necessary	During the currently-reserved time period for evidentiary hearings (*i.e.*, July 17).

VI.

CONCLUSION

WHEREFORE, the Settling Parties respectfully request that the Assigned Commissioner, Assigned ALJs, and the Commission:

1. Approve the attached Settlement Agreement 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.

3. Authorize the withdrawal of the original Motion for Adoption of Revenue Allocation Settlement Agreement filed on July 3, 2018.

Respectfully submitted,

FADIA R. KHOURY
RUSSELL A. ARCHER

/s/ Russell A. Archer

By: Russell A. Archer
Attorneys for

SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
Facsimile: (626) 302-3990
E-mail: Russell.Archer@sce.com

And on behalf of the Settling Parties.[13]

July 13, 2018

[13] 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
Revenue Allocation Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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<u>REVENUE ALLOCATION SETTLEMENT AGREEMENT</u>

Dated: **July 3, 2018**

REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents

REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents (Continued)

REVENUE ALLOCATION SETTLEMENT AGREEMENT

Table of Contents (Continued)

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REVENUE ALLOCATION SETTLEMENT AGREEMENT

This Revenue Allocation Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. Parties

The Parties to this Agreement are Southern California Edison Company (SCE); The Utility Reform Network (TURN); the Office of Ratepayer Advocates (ORA); Small Business Utility Advocates (SBUA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); California City-County Street Light Association (CAL-SLA); 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 California Public Utilities Commission (Commission or 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.

C. ORA represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with safe, reliable service, and the state's environmental goals. Pursuant

[1] The following parties take no position on the Agreement: the Solar Energy Industries Association (SEIA) and the Coalition for Affordable Street Lights (CASL).

to Public Utilities Code Section 309.5(a), ORA 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's Public Utility Code Section 1802.

E. CFBF is California's largest farm organization, working to protect family farms on behalf of its nearly 40,000 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 industrial electric bundled service, CCA and DA customers of PG&E and SCE. These companies are in the steel, cement, industrial gas, pipeline, minerals extraction, and beverage industries.

K. EPUC represents the end-use and customer generation interests of the following companies: Aera Energy LLC, Tesoro Refining & Marketing Company LLC, Chevron U.S.A. Inc., ExxonMobil Power and Gas Services Inc., and California Resources Corporation.

L. CAL-SLA 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.

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

G. "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.

H. "Combustion Turbine" (sometimes referred to as a "CT") means a natural-gas-fueled, simple-cycle combustion turbine electric generator, used in the determination of marginal generation capacity costs.

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. "DWR Revenue Requirement" means the revenues collected by SCE on behalf of the DWR to recover the costs of repaying the bonds that were issued to repay the General Fund of California.

O. “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.

P. “ERRA” means Energy Resource Recovery Account.

Q. “FERC” means the Federal Energy Regulatory Commission.

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. “LOLE” means “Loss of Load Expectation” (sometimes referred to by parties as “LOLP” or Loss of Load Probability), and it represents the expectation that available generation capacity will be inadequate to supply customer demand at any given moment.

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

Z. “NSGC” means New System Generation Charge, and is a cent-per-kWh 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).

AA. “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.

BB. “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.

CC. “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.

DD. “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. The costs reflected in the PCIA are also embedded pro rata in bundled service customers’ generation rates.

EE. “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.

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

GG. “PUCRF” means Public Utilities Commission Reimbursement Fee.

HH. “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.

II. “RPS” means Renewables Portfolio Standard.

JJ. “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.

KK. “SGIP” means Self Generation Incentive Program, with cost allocation as modified by Resolution E-4926.

LL. “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 are implemented periodically when SCE’s authorized revenue requirements change after the initial implementation of this Agreement.

MM. "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.

NN. "SONGS Regulatory Asset" means the remaining $624 million (SCE share, excluding deferred tax assets) of the San Onofre Nuclear Generating Station regulatory asset, which will not be collected from customers if the pending January 30, 2018 Joint Motion for Adoption of Settlement Agreement in Investigation (I.) 12-10-013 is approved by the Commission.[2]

OO. "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.

PP. The "TCJA" means the Federal Tax Cuts and Jobs Act of 2017 (131 Stat. 2054, Pub. L. 115-97) (effective December 22, 2017).

QQ. "TOU" means time-of-use. These are the time periods established for payment 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 are pending adoption in the May 22, 2018 Proposed Decision in A.16-09-003 (SCE's 2016 Rate Design Window proceeding).

3. Recitals

A. Paragraph 4.B.7 of SCE's 2015 General Rate Case (GRC) Marginal Cost and Revenue Allocation Settlement Agreement, which was approved by Decision (D.) D.16-03-030, 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.16-03-030.

[2] Several Settling Parties here, including SCE, ORA, TURN, CLECA and DACC, are signatories to the Joint Motion and the underlying SONGS settlement it supports. On June 23, 2018, the Commission issued a Proposed Decision that would approve the aspects of the SONGS settlement at issue here.

B. In Phase 2 of SCE's 2018 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 June 30, 2017, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 17-06-030.

D. On November 22, 2017, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a November 2, 2017 prehearing conference.

E. ORA served its initial testimony on February 16, 2018.

F. On March 23, 2018, the following Settling Parties submitted prepared testimony regarding marginal costs and/or revenue allocation: TURN, SBUA,[3] CFBF, AECA, CALSLA, DACC, EUF, CLECA, EPUC and FEA.

G. 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 April 6, 2018.

H. Continuing settlement discussions occurred among the parties after April 6, 2018.

I. 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.

J. 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.

K. Appendix B provides illustrative class average rate summaries based on an estimated 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.

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[3] SBUA submitted its prepared testimony on March 21, 2018.

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 participating 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 2021 GRC.

A. Marginal Costs

This Settlement Agreement does not reflect approval or acceptance of any of the Settling Parties' marginal cost proposals. The Settling Parties used 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 will 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

For the purposes of this revenue allocation settlement the Parties agreed to a set of marginal energy costs that vary by season and TOU periods. The energy costs were updated to reflect more recent projections of natural gas prices and GHG costs.

2) Generation Marginal Capacity Costs

For the purposes of this revenue allocation settlement, the Parties agreed on a generation marginal capacity cost that was within the range of values proposed by the Parties. They further agreed that it be allocated to TOU periods by SCE's relative LOLE measure and that it be partly allocated on the basis of peak demand and partly on the basis of the need for ramping capacity, *i.e.*, flexible capacity. As discussed more fully in Paragraph 4.C below, SCE and interested parties have agreed to engage in discussions to explore potential future refinements to the peak/flex generation capacity split for incorporation in SCE's next GRC Phase 2 proceeding.

3) Marginal Customer Costs

For purposes of revenue allocation only, the Parties agreed on marginal customer costs that are within the range of values proposed by the Parties.

4) Marginal Distribution Capacity Cost

For purposes of this Settlement Agreement only, the Parties agreed to marginal distribution capacity costs that are within the range of values proposed by the Parties and based partly on peak-related and partly on grid-related cost elements. SCE agrees to provide additional information regarding the peak/grid distribution capacity split in SCE's next GRC Phase 2 proceeding.[4]

B. Revenue Allocation

In order to avoid further 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 have agreed on how to allocate SCE's total revenue requirement on an overall revenue-neutral basis. This Settlement Agreement is based on a number of assumptions that were used as input to SCE's revenue allocation model that were agreed upon by the Parties solely for the purposes of reaching this Settlement Agreement.

The Settling Parties agree that the 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 an estimated consolidated SCE revenue requirement of $11,420 million in January 2019, which includes revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), Demand Response, Nuclear Decommissioning, the DWR Bond Charge, the New System Generation

4 Specifically, as requested in testimony submitted by ORA, SCE agrees to provide its distribution demand investment, nameplate capacity and load data at the regional level and at the substation level, and to produce a load weighted average distribution design marginal cost at each level of the system.

Charge (NSGC), and the GHG offsets.[5] The illustrative rate levels provided in Appendix B of this Agreement are based on this estimated consolidated SCE revenue requirement and will therefore 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.

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

The 2019 consolidated estimated revenue requirement of $11,420 million is based on SCE's actual January 1, 2018 revenue requirement with the following adjustments:

- Generation revenue requirements include an estimate of the 2019 ERRA Forecast proceeding revenue requirement forecast (A.18-05-003), which includes the sales forecast reflected in SCE's May 1, 2018 Direct Testimony in that proceeding. This sales forecast reflects a bundled service customer/departing load sales split of 64 GWh / 16 GWh, as well as SCE's 2019 Fuel & Purchased Power budget forecast.
- Distribution revenue requirements include SCE's calendar year 2019 proposed revenue requirement from SCE's pending 2018 GRC Phase 1 (A.16-09-001), with a moderated incremental GRC Phase 1 increase of only 50 percent of the initial request. This revenue requirement includes an estimated one-year amortization of SCE's proposed GRC revenue requirement for calendar year 2018, which would refund the revenue requirement delta between SCE's proposal and that reflected in currently-authorized rates. This GRC-related distribution revenue requirement used herein also reflects the estimated impact from the TCJA.
- The revenue requirements also reflect the removal of the SONGS Regulatory Asset from customer rates, retroactive to December 19, 2017 if the pending Proposed Decision in A.16-04-001 is adopted, or April 21, 2018, if it is not.
- Transmission revenue requirements include an estimated reduction in SCE's currently-authorized revenue requirement to reflect the impact from the TCJA.

5 California Climate Credit and the revenues to be returned to EITE customers are included in the estimated consolidated SCE revenue requirement of $11,420 million, but are excluded during the revenue allocation and collaring process.

- The GHG allowance revenues constitute $335 million in SCE's 2019 revenue requirement filed in the 2019 ERRA Application.
- New System Generation is based on the estimated 2019 forecast (A.18-05-003), adjusted to approximate the revenue requirement request in SCE's 2018 GRC Phase 1.
- Nuclear Decommissioning costs are based on estimated year-end 2018 levels.
- Public Purpose Programs, Transmission, DWR Bond Charge, and PUCRF revenue requirement estimates assume levels roughly approximate to 2018 levels.

Table RA-1, below, provides additional detail with respect to the assumed revenue requirements that are reflected in the 2019 estimated consolidated revenue requirement.

Table RA-1
Revenue Requirement Summary Comparison

	January 2018 Revenue Requirements ($000)			GRC Phase 2 Revenue Requirements ($000)			% Change (January 2018 vs. GRC Phase 2)		
	Bundled Service	DA	Total Retail	Bundled Service	DA	Total Retail	Bundled Service	DA	Total Retail
Generation	**5,452,950**	**135,162**	**5,588,112**	**4,584,658**	**134,815**	**4,719,473**	**-16%**	**0%**	**-16%**
New System Generation	**346,780**	**51,408**	**398,188**	**371,957**	**84,373**	**456,330**	**7%**	**64%**	**15%**
Distribution	**3,905,800**	**411,887**	**4,317,686**	**3,746,412**	**706,510**	**4,452,923**	**-4%**	**72%**	**3%**
Distribution O&M and Capital	4,362,260	433,999	4,796,259	4,133,847	756,744	4,890,591	-5%	74%	2%
Self Generation/CA Solar Initiatives	54,469	8,249	62,718	45,456	17,262	62,718	-17%	109%	0%
Other Distribution	(186,886)	(18,593)	(205,479)	(173,684)	(31,795)	(205,479)	-7%	71%	0%
Demand Response	36,631	3,644	40,275	34,043	6,232	40,275	-7%	71%	0%
GHG offsets (Exclude CD & EITE)	(360,674)	(15,413)	(376,087)	(293,249)	(41,933)	(335,183)	-19%	172%	-11%
Nuclear Decommissioning	**3,762**	**638**	**4,400**	**3,418**	**834**	**4,251**	**-9%**	**31%**	**-3%**
Public Purpose Programs	**420,505**	**54,775**	**475,281**	**400,064**	**75,217**	**475,281**	**-5%**	**37%**	**0%**
Energy Efficiency	317,280	46,503	363,783	299,926	63,857	363,783	-5%	37%	0%
CARE Administration	6,183	906	7,089	5,845	1,244	7,089	-5%	37%	0%
Other Public Purpose Programs	97,042	7,366	104,409	94,293	10,115	104,409	-3%	37%	0%
Transmission	**865,581**	**102,190**	**967,772**	**731,031**	**141,998**	**873,029**	**-16%**	**39%**	**-10%**
DWR Bond Charge	**347,164**	**64,080**	**411,243**	**319,783**	**82,154**	**401,937**	**-8%**	**28%**	**-2%**
PUCRF	**32,134**	**5,450**	**37,584**	**29,613**	**7,332**	**36,946**	**-8%**	**35%**	**-2%**
Total Revenue Requirement	**11,374,676**	**825,590**	**12,200,266**	**10,186,936**	**1,233,233**	**11,420,169**	**-10%**	**49%**	**-6%**

A number of variables could either increase or decrease the estimated revenue requirement when this Agreement is implemented and applied to SCE's authorized revenues. For bundled service customers, the estimated consolidated revenue requirement used as a proxy in this Agreement represents a system average rate change from the January 2018 current rate revenue levels of 16.74¢/kWh to estimated 2019 rate levels of 16.25¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's forecasted sales for 2019. For departing load customers, the estimated consolidated revenue requirement used as a proxy in this Agreement represents a system average rate change from the January 2018 current rate revenue levels of 8.27¢/kWh to estimated 2019 rate levels of 8.06¢/kWh (excluding the California Climate Credit and EITE revenue return), based upon SCE's forecasted sales for 2019 as set forth in the April 1, 2018 Direct Testimony supporting A.18-05-003.[6]

2) Collars on Revenues Allocated to Rate Groups

As a result of the revenue allocation methods and marginal costs applied to SCE's CPUC- and FERC-jurisdictional authorized revenue requirements in SCE's Model, each rate group will receive differing amounts of SCE's authorized revenue requirement relative to 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 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 are unaffected by the respective generation or distribution revenue collars. In addition, "secondary capping" will be applied to the delivery rates of the TOU-GS-3 rate class and to the bundled rates of the TOU-8 rate classes. Table RA-2 and the subparts of Paragraph 4.B.2, below, describe these collars and illustrate the results.

[6] These values do not include the net effect, if any, of a subsequent decision in R.17-06-026 (*i.e.*, the Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment).

Table RA-2[7]
January 2018 Rates Compared to Capped Settlement Rates

Retail Delivery Distribution Capping
Direct Access and Bundled-Service Customers

	Jan 2018 Retail Delivery Rate	Uncollared Retail Delivery Rate	Collared Retail Delivery Rate	Uncollared %	Collared %
Residential	10.92	11.06	11.11	1.29%	1.73%
TOU-GS-1	9.88	9.65	9.80	-2.30%	-0.82%
TC-1	12.51	10.68	12.41	-14.67%	-0.82%
TOU-GS-2	9.55	9.41	9.48	-1.49%	-0.82%
TOU-GS-3	7.95	8.30	8.24	4.38%	3.68%
Total LSMP	9.17	9.14	9.19	-0.24%	0.31%
TOU-8-Sec	6.93	7.31	7.22	5.51%	4.18%
TOU-8-Pri	6.05	6.52	6.30	7.80%	4.18%
TOU-8-Sub	2.96	3.09	3.08	4.51%	4.18%
Total LP	5.48	5.81	5.71	6.06%	4.18%
TOU-PA-2	7.47	7.69	7.69	2.96%	2.99%
TOU-PA-3	6.27	6.23	6.23	-0.58%	-0.60%
Total Ag&Pumping	6.94	7.04	7.04	1.54%	1.55%
Total StLights	13.78	14.77	14.36	7.21%	4.18%
STANDBY/SEC	6.92	7.35	7.21	6.20%	4.18%
STANDBY/PRI	6.95	7.44	7.24	7.06%	4.18%
STANDBY/SUB	3.10	3.31	3.23	6.93%	4.18%
Total Standby	4.32	4.61	4.50	6.90%	4.18%
System	8.62	8.77	8.77	1.68%	1.68%

Delivery Collar:	Limits
All rate groups(except TOU-GS-3): SAR + 2.5% cap	4.18%
All rate groups: SAR - 2.5% floor	-0.82%
TOU-GS-3: SAR + 2% cap	3.68%

Generation Capping
Bundled-Service Customers

	Jan 2018 Total Rate	Collared Retail Delivery Rate	Collared Bundled Delivery Rate	Uncollared Generation Rate	Uncollared Total Rate	Collared Generation Rate	Collared Total Rate	Uncollared %	Collared %
Residential	19.47	11.11	11.13	8.60	19.73	8.01	19.13	1.36%	-1.72%
TOU-GS-1	17.77	9.80	9.50	6.59	16.09	7.52	17.02	-9.48%	-4.22%
TC-1	19.08	12.41	12.42	5.89	18.31	6.04	18.46	-4.05%	-3.29%
TOU-GS-2	18.13	9.48	9.98	6.74	16.72	7.39	17.37	-7.81%	-4.21%
TOU-GS-3	16.03	8.24	8.74	6.28	15.03	6.61	15.35	-6.23%	-4.21%
Total LSMP	17.50	9.19	9.54	6.58	16.13	7.22	16.76	-7.85%	-4.21%
TOU-8-Sec	14.24	7.22	7.41	6.11	13.52	6.33	13.74	-5.07%	-3.53%
TOU-8-Pri	12.87	6.30	6.46	5.90	12.35	5.96	12.42	-4.04%	-3.53%
TOU-8-Sub	9.02	3.08	3.09	5.56	8.65	5.62	8.71	-4.11%	-3.53%
Total LP	12.36	5.71	5.90	5.90	11.79	6.02	11.92	-4.57%	-3.53%
TOU-PA-2	14.82	7.69	7.79	6.21	14.00	6.41	14.19	-5.53%	-4.22%
TOU-PA-3	12.03	6.23	6.23	5.87	12.09	5.57	11.80	0.56%	-1.89%
Total Ag&Pumping	13.57	7.04	7.09	6.06	13.14	6.03	13.12	-3.11%	-3.29%
Total StLights	18.52	14.36	14.54	5.57	20.11	3.66	18.20	8.61%	-1.72%
STANDBY/SEC	14.52	7.21	7.55	6.00	13.55	6.36	13.91	-6.69%	-4.21%
STANDBY/PRI	13.84	7.24	7.24	5.99	13.22	6.02	13.26	-4.47%	-4.22%
STANDBY/SUB	9.04	3.23	3.18	5.35	8.53	5.48	8.66	-5.63%	-4.22%
Total Standby	10.45	4.50	4.36	5.53	9.89	5.65	10.01	-5.41%	-4.22%
System	16.74	8.77	9.12	7.12	16.25	7.12	16.25	-2.97%	-2.97%

Generation Collar:	Limits
All rate groups: SAR + 1.25% cap	-1.72%
All rate groups: SAR - 1.25% floor	-4.22%

Table RA-3, below, lists the functional revenue allocator percentages that shall be used to allocate each unbundled revenue requirement to each rate group based on these principles.[8] 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 (2013-2015), as reflected in SCE's work papers.

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[7] The tables in this Settlement Agreement list revenues or rates for the Agricultural and Pumping rate groups, TOU-PA-2 and TOU-PA-3. The level of revenues allocated to the combined Agricultural and Pumping rate groups is established by this Settlement Agreement. However, the allocation of revenues between the two rate groups may be adjusted as a result of various elements to be addressed in the rate design phase specific to agricultural customers. If any such adjustments are made, the dollar amount of revenues allocated between the two agricultural rate groups shall be specifically identified in any agricultural rate design settlement agreement using the same revenue requirement and load forecast assumptions as were used in the this settlement.

[8] SCE has included a comparison version of Table RA-3 in Appendix C hereto that reflects SCE's litigation position, as modified by the updated inputs used in SCE's Model during settlement negotiations. Those inputs include: (1) inputs of the TCJA changes; (2) updates in marginal energy costs related to updated natural gas price forecasts; and (3) an updated SCE sales forecast.

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 2009-2015. 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-3
GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

	Uncapped	Capped	Uncapped	Capped						
	Distribution		Generation		APS & Interruptible Surcharge[1]	CSI[2]	SGIP[3]	PPP[4]	NDC/PUCRF[5]	NSGC[6]
Total Domestic	50.3%	50.4%	45.1%	41.7%	40.5%	35.7%	0.6%	40.1%	33.6%	40.6%
TOU-GS-1	7.8%	8.0%	7.6%	8.7%	6.9%	8.8%	0.3%	8.1%	7.3%	7.5%
TC-1	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%
TOU-GS-2	16.6%	16.8%	15.3%	16.9%	15.5%	19.0%	7.2%	17.5%	16.2%	17.6%
TOU-GS-3	8.1%	8.1%	7.6%	8.0%	8.8%	10.0%	21.6%	9.2%	9.7%	9.3%
Total LSMP	32.6%	33.0%	30.5%	33.7%	31.3%	37.8%	29.1%	34.9%	33.3%	34.5%
TOU-8-Sec	7.3%	7.1%	7.7%	7.9%	9.0%	9.4%	34.8%	8.6%	10.0%	8.7%
TOU-8-Pri	4.8%	4.6%	5.2%	5.2%	6.5%	5.8%	18.0%	5.4%	6.8%	5.3%
TOU-8-Sub	1.3%	1.3%	6.1%	6.2%	7.6%	4.4%	6.1%	4.1%	7.3%	4.9%
Total Large Power	13.3%	12.9%	18.9%	19.3%	23.1%	19.6%	59.0%	18.1%	24.1%	18.9%
TOU-PA-2	2.0%	2.0%	2.3%	2.3%	2.0%	2.2%	0.8%	2.0%	2.3%	1.7%
TOU-PA-3	1.1%	1.1%	1.7%	1.6%	1.5%	1.4%	2.0%	1.3%	1.8%	1.1%
Total Ag&Pumping	3.1%	3.1%	4.0%	4.0%	3.5%	3.7%	2.8%	3.4%	4.0%	2.7%
Total Street Lighting	0.2%	0.2%	0.7%	0.4%	0.7%	0.5%	0.0%	1.0%	0.9%	0.5%
STANDBY/SEC	0.1%	0.1%	0.1%	0.1%	0.1%	0.3%	1.4%	0.2%	0.3%	0.2%
STANDBY/PRI	0.2%	0.2%	0.2%	0.2%	0.2%	0.9%	7.1%	0.8%	1.0%	0.7%
STANDBY/SUB	0.1%	0.1%	0.5%	0.5%	0.6%	1.7%	0.0%	1.5%	2.7%	1.8%
Total Standby	0.4%	0.4%	0.8%	0.9%	0.9%	2.8%	8.5%	2.6%	4.0%	2.8%
Total System	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] APS and interruptible surcharge are allocated based on the marginal cost of generation revenue requirement for all retail sales
[2] CSI revenues are allocated based on each group's proportion of system revenues, excluding CARE and FERA customers, and streetlight facilities
[3] SGIP revenues are allocated based on the proportion of incentives given to each rate groups
[4] PPP revenues are allocated to rate groups on a proportion of system revenues, with DA/CCA customers imputed as bundled customers
[5] NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis
[6] NSGC is allocated to all retail customers based on the 12-CP allocators
DCARE surcharge is allocated on an equal ¢/kWh basis, excluding the DCARE and streetlight customers
DWRBC is allocated on an equal ¢/kWh basis, excluding the DCARE customers

a) **<u>Delivery Service Collars For Allocated Revenues (Affects Departing Load and Bundled Service Customers)</u>**

For the delivery service collar, the Settling Parties agree to remove all GHG allowance *revenues*, from the estimated consolidated revenue requirement in Table RA-2. The Settling Parties agree to allocate delivery service revenues to the rate groups in accordance with the collared allocators shown in Table RA-3 using a collar of the Functional SAR change for delivery services plus or minus 2.5 percent, and a secondary cap of 2.0 percent for the TOU-GS-3 class.

b) **<u>Generation Revenues Collars on Bundled Service Rates (Affects Bundled Service Customers Only)</u>**

For the generation revenue collar, the Settling Parties agree not to remove the GHG *costs* from the estimated 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-3, using a collar of the SAR change for (bundled) generation services plus or minus 1.25 percent, and a secondary cap for the Non-Standby large power rate group (*i.e.*, TOU-8) set to class average decrease of 3.5 percent.

3) **<u>Establishment of Street Light Rate Group Non-Allocated Revenues</u>**

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 $76 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) **<u>Allocation of CPUC and FERC-Authorized Revenue Requirements</u>**

The Settling Parties agree that all of SCE's CPUC- and FERC-jurisdictional revenue requirements as reflected in the estimated 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 estimated 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 estimated consolidated revenue requirement are also shown in Appendix B.

5) **Functional Revenue Requirements**

Without effecting any change to this Agreement and the illustrative rates provided in Appendix B, 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 estimated 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-3. FERC-jurisdictional rate components shall be added to the CPUC-jurisdictional delivery rates, resulting in total delivery service rates.[9]

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-2, above, SCE's distribution revenue requirement reflected in the estimated consolidated revenue requirement shown in Table RA-1 shall be allocated to rate groups based on the applicable distribution functional allocators shown in Table RA-3.

(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

[9] The future FERC revenue requirements may also be impacted by the results of the "transmission cost causation study" ordered by the Commission in D.18-05-040 at p. 114 and Ordering Paragraph 43. SCE will include the results of this transmission cost causation study in its 2021 GRC Phase 2 proceeding.

service and departing load customers based on the system generation allocators shown in Table RA-3.

(3) 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.

(4) 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-cent-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-2, above, the generation revenue requirement reflected in the estimated 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-3, above.

d) **<u>DWR Bond Charge Revenue Requirement</u>**

The DWR Bond Charge revenue requirement shall be recovered based on the DWR Bond Charge as authorized in the appropriate CPUC proceedings, which is on an equal cents per kilowatt-hour basis, including all retail sales but excluding CARE customers.

e) **<u>Nuclear Decommissioning Revenue Requirement</u>**

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-3, above, and shall be recovered as a cent-per-kilowatt-hour charge designated in SCE's tariffs as the NDC.

f) **<u>Public Purpose Programs (PPP) Revenue Requirement</u>**

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-kWh basis.

g) **CARE Balancing Account Revenue Requirement**

The revenues associated with the discount provided to CARE customers shall be allocated to rate groups on an equal cents per kWh 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) **CSI and SGIP Revenue Requirements**

The CSI revenue requirement that is reflected in the estimated consolidated revenue requirement (Table RA-1) shall be allocated to rate groups based on the CSI revenue allocator listed in Table RA-3, and which 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, but excluding CARE and FERA revenues as well as Street Light Non-Allocated Revenues. The CSI revenue requirement will be recovered in non-CARE-customers' rates on a cent-per-kWh basis in the distribution component of SCE's delivery charges.

The SGIP revenue requirement that is reflected in the estimated consolidated revenue requirement (Table RA-1) shall be allocated to rate groups based on the SGIP revenue allocator listed in Table RA-3, 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 cent-per-kWh basis in the Public Purpose Programs Charge.

i) **New System Generation Revenue Requirement**

The NSG revenue requirement shall be allocated using the 12 monthly system coincident peak (12-CP) revenue allocators shown in Table RA-3.

6) **Adjustments to Revenue Requirements When Agreement Is First Implemented**

The revenues and rates reflected in Appendix B are illustrative and based on the estimated consolidated revenue requirement of $11,420 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 estimated 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. To maintain the same relationship between SAPC and percentage change relative to SAPC for each rate group, run SCE's Model with the same input settlement 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, CSI 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, develop the revised collared functional revenue allocators; and
- To complete the revenue allocation process, apply the revised collared functional distribution and generation revenue allocators to the revised CPUC-authorized revenue requirements, add the FERC-authorized revenue requirements per rate group, and add the Street Light rate group Non-Allocated Revenues back to the Street Light rate group so as to develop the portion of SCE's authorized revenue requirement that is allocated to each rate group.

7) <u>Future Changes to SCE's Consolidated Revenue Requirement</u>

a) <u>Future Distribution and Generation Revenue Changes</u>

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 on a Functional SAPC basis reflecting 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. 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
4. 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.[10]

b) **Future CSI and 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 CSI and SGIP revenue requirements shall be allocated using the CSI and SGIP revenue allocators listed in Table RA-3. For future CSI and SGIP revenue changes, the difference between the CSI and SGIP revenues reflected in the estimated consolidated revenue requirement ($62.7 million shown in Table RA-1) 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 of 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-3.

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, CSI, 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 generation revenues for departing load customers imputed as if they were bundled service customers, and the remaining 50 percent

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10 This calculation is performed by multiplying these billing determinants by the current rates. Adjustments to account for customers served on optional rates will be made such that any revenue deficiency is contained within the individual rate class (*e.g.*, TOU-GS-1, TOU-GS-2, TOU-PA-2) in which the deficiency exists.

of the demand response program administration and incentive revenue requirement will be allocated by the collared distribution revenue allocators in Table RA-3.

C. Future Generation Capacity Flex Study

Within one year of the adoption of this Agreement, SCE and interested parties have agreed to create a working group to discuss how to incorporate a flexible generation capacity component into the revenue allocation process in addition to a peak capacity component. In particular, the working group will seek to understand the factors such as load and renewable resources that affect the ramp requirement and how they can be reflected in the allocation of generation capacity 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 2021 GRC Phase 2 and for the study described in this section. Other stakeholders, such as PG&E, SDG&E, the Commission's Energy Division and the CAISO, 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 2021 GRC Phase 2 Application (and serves its supporting testimony), that will explore the relationship between "peak" and "flex" as generation capacity marginal costs, and which may be used for proposing refinements to the relative weighting of peak and flex loads for revenue allocation purposes.

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 January 1, 2019.

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 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 2018 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: June 29, 2018 SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Caroline Choi
By: Caroline Choi
Title: Senior Vice President, Regulatory Affairs

Dated: June 29, 2018 THE UTILITY REFORM NETWORK

/s/ Hayley Goodson
By: Hayley Goodson
Title: Staff Attorney

Dated: July 3, 2018 SMALL BUSINESS UTILITY ADVOCATES

/s/ James Birkelund
By: James Birkelund
Title: President

Dated: July 2, 2018 OFFICE OF RATEPAYER ADVOCATES

/s/ Darwin Farrar
By: Darwin Farrar
Title: Chief Counsel

Dated: June 29, 2018 CALIFORNIA FARM BUREAU FEDERATION

/s/ Karen Norene Mills
By: Karen Norene Mills
Title: Associate Counsel

Dated: July 3, 2018 AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

/s/ Michael Boccadoro
By: Michael Boccadoro
Title: Executive Director

Dated: July 2, 2018 FEDERAL EXECUTIVE AGENCIES

/s/ Rita M. Liotta
By: Rita M. Liotta
Title: Counsel

Dated: July 2, 2018

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Counsel

Dated: July 2, 2018

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Attorney

Dated: July 2, 2018

ENERGY PRODUCERS AND USERS COALITION

/s/ Katy Morsony

By: Katy Morsony
Title: Counsel

Dated: July 2, 2018

ENERGY USERS FORUM

/s/ Carolyn Kehrein

By: Carolyn Kehrein
Title: Consultant

Dated: July 3, 2018

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

/s/ Daniel Denebeim

By: Daniel Denebeim
Title: Attorney

Dated: June 29, 2018

DIRECT ACCESS CUSTOMER COALITION

/s/ Daniel W. Douglass

By: Daniel W. Douglass
Title: Counsel

Appendix A

Comparison of Party Positions and Settlement

Revenue Allocation

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
General Position	Use filed MCs and sales forecast	Use own MCs and adjusted sales forecast	Use own MCs	Use NCO methodology to modified to add ancillary costs	Generally supports SCE's proposals				Doesn't support ORA's MC/RA proposals	Generally supports SCE's proposals but wants 2010-2015 data used for peak DDMCs and GCMCs – but CPUC should make no changes in rates as a result of MC/RA updates	Revenue allocations should be frozen		N/A
Capping / Collaring	Did not propose	Gen: 2.5%/-2.7% Del: +/-5%	Bundled: +/-3% Del: +/-6% Treat A&P as single class	Propose no capping	Didn't propose due to modeling issues, but would likely support capping	Didn't propose, but generally support capping if consistently applied to Bundled and DA/CCA and price signals are kept intact			Support ORA's capping proposal Don't mix across delivery and generation	Didn't propose but supports capping; implement separately for small and large Ag		Supports ORA's capping proposal	Del: +/-2.5% Gen: +/-1.25% Secondary Caps: 2% Del cap for TOU-GS-3 Class avg decrease for each non-Standby TOU-8 sub-group (-3.5%) (bundled)

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
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 TOU sales in each rate class, where the TOU sales are grouped in the proposed	Allocate by generation allocation factor derived by EPMC – use own MCs		Overallocation to small businesses	CLECA supports SCE's peak / flex split Propose a different GCMC so percent share of energy vs. capacity is different		Propose alternative ramp allocation that addresses both utility scale solar impacts and change in individual customer class loads across the ramp period	Propose alternative ramp allocation that addresses both utility scale solar impacts and change in individual customer class loads across the ramp period		Use 2010-2015 data for Ag top 100 hours for both peak and ramp			Based on the generation functional allocators shown in Table RA-3, subject to collaring

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
	TOU periods Generation Capacity MCRR - for peak capacity costs, allocation is based on the average rate group load (MW) during the top 100 net load hours of the year as a percent of the total average net loads in the top 100 hours; for flexible capacity costs, allocation is based on the 3-hour average rate group load (MW) as a portion of the total 3-hour average load during the top 100 largest 3-hour net load ramp hours of the year												

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
Distribution Revenues	Peak: PLRF Grid: NCP x EDF x Cost Customer: MC x Forecasted Customers Non-allocated revenues specifically assigned to street lights of $76,650,000	Allocate by distribution allocation factor derived by EPMC – use own MCs	Use demand distribution scalars	Overallocation to small businesses	Supports SCE's proposal					Use 2010-2015 data for Ag when applying PLRFs			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 consistent with the 2015 GRC Phase 2 Settlement Agreement Non-allocated revenues assigned directly to street light of $76,466,000 w/ recovery addressed in rate design phase of proceeding

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
Public Purpose Programs	Assign revenues to rate groups on a system average percentage w/ generation revenues imputed for DA/CCA			Transmission revenue allocation Bond overallocated to small businesses	Prefer that CARE is sequestered to res or use SAPC								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 allocated to rate groups on an equal cents per kWh basis including DA/CCA sales, but excluding the kWh usage of CARE and street light customers
Self-Generation Incentive Program	Assign revenues to rate groups on a system average percentage		Allocation should be per D.16-06-055		Use SAPC, with generation revenues imputed for DA/CCA								Per Resolution E-4926, allocation is based on the proportion of incentives disbursed to each rate group over

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
													the most recent three years; update the allocation on a rolling basis annually
Nuclear Decommissioning	Allocated on an equal cents / kWh basis to rate groups for all retail customers				Supports SCE but prefers a generation allocation								Allocate to all rate groups, based on energy consumption reflecting total retail sales, recovered on a cents per kWh charge designated in SCE's tariffs as the NDC
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		Generation revenues should be imputed for Da/CCA and included in distribution rate if MEC/MGCC is used								Collared distribution revenue allocators applied to DR rev req shall be modified such that 50% of DR rev req will be allocated be each rate group's proportional share of system revenues,

Issue	SCE	ORA	TURN	SBUA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	CALSLA	Settled Position
													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 $17M EE shareholder incentives using distribution allocator (Resolution E-4807) Use PPPC allocator for EPIC and Procurement EE		Allocate $17M EE shareholder incentives and $6.1M EV pilot programs using PPPC allocator w/ gen imputed for DA/CCA		Use SAPC for EPIC/EE								Same as Demand Response above

Marginal Costs

Issue	SCE[1]	ORA	TURN	SEIA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	SBUA	CALSLA	Settled Position
GCMCs ($/kW-yr w/o RA adder)	$135.50, based on the deferral value of a new build CT proxy resource (LMS100), net of energy rents, with O&M and property tax costs include	$57.92, based on a combination of (1) a mixture of current bilateral and other market prices and SCE's $134.50 CT proxy and (2) a mixed short-run/long-run (six-yr) approach	Believes ORA's GCMC reflect current conditions, but provide a value of $115.70 if SCE's CT deferral method is used (includes lower cost of capital, tax law changes, reduced property tax rate, insurance, modified A&G); deducts energy rents	Supports SCE's proposal but believes storage may become an economic source over the next five years	$152.50, based on the deferral value of an LMS100 CT, with higher O&M costs from CEC report (including insurance); do not deduct energy rents	Supports SCE's proposal and use of long-run marginal costs and not a mixture of long-run and short-run or just short-run; disagrees w/ ORA's characterization that we are in a period of surplus capacity	$215, based on the deferral value of an LMS600; include tax law impacts and do not deduct energy rents	$215, based on the deferral value of an LMS600; include tax law impacts and do not deduct energy rents			Believe storage and solar may be more appropriate capacity metric than a CT, but propose that no updates be made given that the costs for storage and solar are not yet sufficiently stable More appropriate to use GBMC			Parties agreed on a generation marginal capacity cost that was within the range of values proposed by parties
Peak / Flex Split of GCMCs	$82 Peak (61%) / $52.5 Flex (39%), ratio derived by taking the max of the monthly average ramps	$36.33 Peak / $79.52 Flex (use 50/50 weighted avg); weights based on SCE's allocation	Supports ORA's proposal		Supports SCE's proposal		Propose alternative ramp allocation that addresses both utility scale solar impacts and change in	Propose alternative ramp allocation that addresses both utility scale solar impacts and change in						Parties agreed to allocate generation capacity costs partly on the basis of peak demand and partly

1 During settlement discussions, SCE updated its filed positions to account for the impacts of the TCJA – which are not shown here but were made available and considered during the negotiations.

Issue	SCE[1]	ORA	TURN	SEIA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	SBUA	CALSLA	Settled Position
	(MW) and the max of the monthly average net load peaks (MW) that occurred during peak and ramp LOLE events for 2018	of GCMC to peak and flex capacities for 2020 and 2021					individual customer class loads across the ramp period	individual customer class loads across the ramp period						on the basis of the need for ramping capacity, *i.e.*, flexible capacity. SCE to engage w/ parties to further refine the allocation of flex capacity for incorporation in SCE's next GRC Phase 2
MECs (¢/kWh)	Summer: On – 4.88 Mid – 4.40 Off – 3.56 Winter: Mid – 4.62 Off – 3.91 SOff – 2.48 Gas Price: $3.37/ mmBTU GHG Price: $0.982/ mmBTU Derived using production simulation model (PLEXOS)	Summer: On – 4.49 Mid – 4.10 Off – 3.56 Winter: Mid – 4.26 Off – 3.81 SOff – 2.86 Derived using PLEXOs and model framework proposed by CAISO Adjust (1) SCE's GHG price forecast consistent with CPUC's	Supports ORA's proposals		Supports SCE's proposal but notes that forecast of annual accumulative DR appears low Opposes use of GHG planning price and RPS adder (but needs to be shaped, if included)	Supports SCE's proposal, but should update natural gas price; shouldn't assume all GHG compliance costs are marginal Does not support ORA's proposals	Support SCE's proposal, but should update gas price if a material change Proposes reductions to GHG compliance costs and RPS adder if ORA's MECs are used	Support SCE's proposal, but should update gas price if a material change Proposes reductions to GHG compliance costs and RPS adder if ORA's MECs are used			Inappropriate to use hourly prices to set MECs; should use mix of MECs and IOU RPS MPB but long-term price from IRP not yet available so proposes making no updates			Parties agreed to a set of marginal energy costs that vary by season and TOU periods; the settled energy costs were updated for recent projection of natural gas prices and GHG costs

Issue	SCE[1]	ORA	TURN	SEIA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	SBUA	CALSLA	Settled Position
		GHG planning price and (2) base wholesale prices to incorporate RPS adder												
Customer MC Method	SCE's RECC	ORA's NCO Use gross customer growth (not net), include a replacement cost adder and exclude uncollectibles	TURN's NCO Use lower replacement rate, lower PVRR, remove uncollectibles / service charge and correct tax life for meters		SCE's RECC Uncollectibles should not be removed Recommend SCE develop a study of new customer accounts	SCE's RECC	SCE's RECC	SCE's RECC	SCE's RECC	SCE's NCO Disagree w/ ORA's customer growth proxy	More appropriate to use GBMC, but proposes no updates should be made	ORA's NCO Believe there are ancillary cost not properly accounted for and want MC for 3-phase reduced	ORA's NCO	Parties agreed on marginal customer costs that were within the range of values proposed by the parties
DDMCs ($/kW-yr)	$167.9, 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)	$168.0; uses own circuit line mile method for apportioning costs between peak and non-peak	$230; incorporates updated cost of capital, tax law impacts, removes A&G and lowers insurance Believes there is a mismatch between demand kW used to calculate	$167.9	Disagrees with SCE's use of planned capacity instead of actual cumulative load	Supports SCE's proposal			Supports SCE's proposal over ORA's	Supports SCE's proposal over ORA's, but would like 2010-2015 data used for ag (not just 2015)	More appropriate to use GBMC, but proposes no updates should be made SCE's method results in an overinvestment in substation capacity in rural areas			Parties agreed to a marginal distribution capacity cost within the range of values proposed by the parties

Issue	SCE[1]	ORA	TURN	SEIA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	SBUA	CALSLA	Settled Position
	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		costs and much lower demand used to allocate costs, so propose an alternate scaling methodology											
Peak / Grid Split of DDMCs	$83 Peak (49.4%) / $84.9 Grid (50.6%)	$152.6 Peak (90.8%) / $15.4 Grid ("Non-Peak") (9.2%) Request that SCE provide additional information in next GRC Phase 2 to better inform analysis	All subtrans costs should be peak but at minimum ORA's proposed 50/50 split on lines; support ORA's proposal over SCE's for dist circuits If SCE's method is used, split should be 37.1% peak / 62.0% grid	Use ORA's peak / grid split but further split peak between coincident and non-coincident	Supports SCE's functionalizing of peak and grid; opposes ORA's proposed split	Supports SCE's proposal								Parties agreed on a split allocation of DDMCs based partly on peak-related and partly on grid-related cost elements within the range of values proposed by the parties
Sales Forecast	Use kWh sales	Lower DG forecast	Agree w/ ORA's		Any updates	Any updates					Adjustment	Agree w/sales		Used SCE's 2019 sales

Issue	SCE[1]	ORA	TURN	SEIA	CLECA	EUF	EPUC	FEA	DACC	CFBF	AECA	SBUA	CALSLA	Settled Position
	forecast for 2018 as the basis for the billing determinant forecast and rate design proposals, as filed in A.16-09-001 Reflects the energy that SCE expects to deliver to Bundled Service, DA and CCA customers in its service territory during the 2018-2020 period	by 528 GWh (residential only)	proposal to update DG forecast		should apply to all classes	should apply to all classes					mechanism needed to address agricultural sales volatility	forecast of SCE		forecast w/ updated bundled/ non-bundled split

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]

Phase 2 Revenue Allocation Agreement
Bundled Service Rate Groups (without California Climate Credit and EITE Credits)
Illustrative Rates

	January 2018	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	19.5	19.7	19.1	1.1%	-1.7%	116%	118%
TOU-GS-1	17.8	15.9	17.0	-10.3%	-4.2%	106%	105%
TC-1	19.1	16.6	18.5	-13.1%	-3.3%	114%	114%
TOU-GS-2	18.1	16.6	17.4	-8.2%	-4.2%	108%	107%
TOU-GS-3	16.0	15.1	15.4	-5.9%	-4.2%	96%	94%
Total LSMP	17.5	16.1	16.8	-8.2%	-4.2%	105%	103%
TOU-8-Sec	14.2	13.6	13.7	-4.4%	-3.5%	85%	85%
TOU-8-Pri	12.9	12.6	12.4	-2.4%	-3.5%	77%	76%
TOU-8-Sub	9.0	8.7	8.7	-4.0%	-3.5%	54%	54%
Total Large Power	12.4	11.9	11.9	-3.7%	-3.5%	74%	73%
TOU-PA-2	14.8	14.0	14.2	-5.6%	-4.2%	89%	87%
TOU-PA-3	12.0	12.1	11.8	0.6%	-1.9%	72%	73%
Total Ag&Pumping	13.6	13.1	13.1	-3.1%	-3.3%	81%	81%
Total Street Lighting	18.5	20.5	18.2	10.9%	-1.7%	111%	112%
STANDBY/SEC	14.5	13.7	13.9	-5.7%	-4.2%	87%	86%
STANDBY/PRI	13.8	13.4	13.3	-3.0%	-4.2%	83%	82%
STANDBY/SUB	9.0	8.6	8.7	-4.7%	-4.2%	54%	53%
Total Standby	10.5	10.0	10.0	-4.3%	-4.2%	62%	62%
Total System	16.7	16.2	16.2	-3.0%	-3.0%	100%	100%

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

Phase 2 Revenue Allocation Agreement
Direct Access / CCA Rate Groups (without California Climate Credit and EITE Credits)
Illustrative Rates

	January 2018	Uncapped Rates	Proposed Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	12.68	12.02	12.08	-5.2%	-4.8%	153%	150%
TOU-GS-1	10.74	10.12	10.26	-5.8%	-4.4%	130%	127%
TC-1	13.24	11.15	12.87	-15.8%	-2.8%	160%	160%
TOU-GS-2	9.09	8.57	8.62	-5.7%	-5.2%	110%	107%
TOU-GS-3	7.88	7.95	7.90	0.8%	0.2%	95%	98%
Total LSMP	8.79	8.49	8.51	-3.3%	-3.1%	106%	106%
TOU-8-Sec	7.60	7.66	7.57	0.8%	-0.3%	92%	94%
TOU-8-Pri	6.74	6.94	6.74	3.0%	0.0%	81%	84%
TOU-8-Sub	3.68	3.67	3.66	-0.1%	-0.4%	44%	45%
Total Large Power	6.04	6.12	6.03	1.3%	-0.2%	73%	75%
TOU-PA-2	7.07	6.83	6.83	-3.4%	-3.5%	86%	85%
TOU-PA-3	6.90	6.75	6.75	-2.2%	-2.2%	83%	84%
Total Ag&Pumping	7.01	6.80	6.80	-3.0%	-3.0%	85%	84%
Total Street Lighting	12.88	13.78	13.41	7.0%	4.1%	156%	166%
STANDBY/SEC	5.89	6.28	6.17	6.8%	4.9%	71%	77%
STANDBY/PRI	7.12	7.59	7.39	6.7%	3.9%	86%	92%
STANDBY/SUB	3.51	3.64	3.55	3.6%	0.9%	42%	44%
Total Standby	5.00	5.27	5.13	5.5%	2.8%	60%	64%
Total System	8.3	8.1	8.1	-2.2%	-2.5%	100%	100%

[1] Excludes Climate Dividends, and EITE Credits

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

Phase 2 Revenue Allocation Agreement
Proposed Bundled Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	Generation	Total Bundled
Total Domestic	333.5	1,779.6	557.1	2,670.2	1,921.0	4,591.2
TOU-GS-1	62.4	321.7	117.8	502.0	397.6	899.6
TC-1	0.3	5.0	1.1	6.4	3.1	9.6
TOU-GS-2	124.4	675.0	237.6	1,036.9	768.6	1,805.5
TOU-GS-3	62.3	294.4	125.2	481.8	364.1	845.9
Total LSMP	249.4	1,296.1	481.7	2,027.2	1,533.4	3,560.6
TOU-8-Sec	54.3	235.6	127.9	417.8	357.4	775.2
TOU-8-Pri	30.3	127.7	76.6	234.5	217.1	451.6
TOU-8-Sub	24.5	24.0	67.5	116.0	210.8	326.7
Total Large Power	109.1	387.3	271.9	768.3	785.3	1,553.6
TOU-PA-2	12.9	83.4	33.0	129.2	106.4	235.6
TOU-PA-3	8.9	49.9	25.4	84.2	75.3	159.5
Total Ag&Pumping	21.8	133.3	58.4	213.4	181.7	395.1
Total Street Lighting	2.8	73.0	9.2	85.0	21.4	106.4
STANDBY/SEC	2.0	7.1	4.1	13.2	11.1	24.3
STANDBY/PRI	4.6	21.3	13.3	39.2	32.6	71.8
STANDBY/SUB	11.1	14.8	31.4	57.3	98.6	155.9
Total Standby	17.6	43.2	48.9	109.7	142.3	252.0
Total System	**734.1**	**3,712.4**	**1,427.3**	**5,873.8**	**4,585.0**	**10,458.9**

Includes NSGS in "Other" category

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

Phase 2 Revenue Allocation Agreement
Proposed DA/CCA Service Revenues
Adjusted Consolidated Revenue Requirement ($MM)
(Illustrative)

	Transmission	Distribution	Other	Total Delivery	PCIA, CTC, DWRPC	Total DA/CCA
Total Domestic	41.9	220.5	68.6	331.1	33.4	364.5
TOU-GS-1	7.3	37.9	13.8	59.1	4.5	63.6
TC-1	0.0	0.6	0.1	0.7	0.0	0.7
TOU-GS-2	20.6	118.1	60.6	199.3	29.2	228.4
TOU-GS-3	17.5	90.0	51.5	159.0	20.1	179.1
Total LSMP	45.4	246.6	126.0	418.0	53.8	471.8
TOU-8-Sec	19.6	87.8	54.0	161.3	19.0	180.3
TOU-8-Pri	13.4	58.8	39.1	111.3	13.8	125.0
TOU-8-Sub	14.6	12.2	38.1	64.9	12.7	77.6
Total Large Power	47.6	158.8	131.2	337.5	45.4	382.9
TOU-PA-2	0.7	5.6	3.0	9.3	1.0	10.3
TOU-PA-3	0.5	3.3	1.6	5.5	0.4	5.8
Total Ag&Pumping	1.3	8.9	4.6	14.8	1.4	16.2
Total Street Lighting	0.5	12.9	1.8	15.2	0.0	15.2
STANDBY/SEC	0.4	1.6	1.2	3.2	0.1	3.3
STANDBY/PRI	2.1	9.5	6.0	17.5	0.4	17.9
STANDBY/SUB	2.9	3.5	6.6	13.1	0.4	13.4
Total Standby	5.4	14.6	13.8	33.8	0.8	34.6
Total System	**142.2**	**662.2**	**346.0**	**1,150.4**	**134.8**	**1,285.2**

Includes NSGS in "Other" category

Appendix C

Comparison Version of Table RA-3-1

Table RA-3-1
Phase 2 Revenue Allocation Agreement
GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

	Uncapped	Uncapped						
	Distribution	Generation	APS & Interruptible Surcharge[1]	CSI[2]	SGIP[3]	PPP[4]	NDC/PUCRF[5]	NSGC[6]
Total Domestic	51.3%	44.8%	40.1%	35.7%	0.6%	40.1%	33.6%	40.6%
GS-1	8.0%	7.6%	6.9%	8.8%	0.3%	8.1%	7.3%	7.5%
TC-1	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%
GS-2	16.7%	15.6%	15.9%	19.0%	7.2%	17.5%	16.2%	17.6%
TOU-GS-3	7.7%	7.7%	9.0%	10.0%	21.6%	9.2%	9.7%	9.3%
Total LSMP	32.6%	31.0%	31.8%	37.8%	29.1%	34.9%	33.3%	34.5%
TOU-8-Sec	6.8%	7.7%	9.1%	9.4%	34.8%	8.6%	10.0%	8.7%
TOU-8-Pri	4.5%	5.1%	6.5%	5.8%	18.0%	5.4%	6.8%	5.3%
TOU-8-Sub	1.1%	6.0%	7.5%	4.4%	6.1%	4.1%	7.3%	4.9%
Total Large Power	12.3%	18.9%	23.1%	19.6%	59.0%	18.1%	24.1%	18.9%
TOU-PA-2	2.1%	2.3%	2.0%	2.2%	0.8%	2.0%	2.3%	1.7%
TOU-PA-3	1.1%	1.7%	1.5%	1.4%	2.0%	1.3%	1.8%	1.1%
Total Ag.&Pumping	3.1%	4.0%	3.5%	3.7%	2.8%	3.4%	4.0%	2.7%
Total Street Lighting	0.2%	0.6%	0.6%	0.5%	0.0%	1.0%	0.9%	0.5%
STANDBY/SEC	0.1%	0.1%	0.1%	0.3%	1.4%	0.2%	0.3%	0.2%
STANDBY/PRI	0.2%	0.2%	0.2%	0.9%	7.1%	0.8%	1.0%	0.7%
STANDBY/SUB	0.1%	0.5%	0.6%	1.7%	0.0%	1.5%	2.7%	1.8%
Total Standby	0.4%	0.8%	0.9%	2.8%	8.5%	2.6%	4.0%	2.8%
Total System	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] APS and interruptible surcharge are allocated based on the marginal cost of generation revenue requirement for all retail sales

[2] CSI revenues are allocated based on each group's proportion of system revenues, excluding CARE and FERA customers, and streetlight

[3] SGIP revenues are allocated based on the proportion of incentives given to each rate groups

[4] PPP revenues are allocated to rate groups on a proportion of system revenues, with DA/CCA customers imputed as bundled customers

[5] NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis

[6] NSGC is allocated to all retail customers based on the 12-CP allocators

DCARE surcharge is allocated on an equal ¢/kWh basis, excluding the DCARE and streetlight customers

DWRBC is allocated on an equal ¢/kWh basis, excluding the DCARE customers