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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, Design Rates, and Implement Additional Dynamic Pricing Rates	))))	Application 11-06-007 (Filed June 6, 2011)

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

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Pursuant to Rule 12.1 *et seq* of the Commission's Rule of Practice and Procedure, Southern California Edison Company (SCE), on behalf of itself and the Settling Parties,[1] requests that the Commission adopt and find reasonable the "Marginal Cost and Revenue Allocation Settlement Agreement," (Settlement Agreement) which is appended to this motion as Attachment A.

The Settling Parties have reached a Settlement Agreement that resolves all issues that have been raised with respect to marginal cost and revenue allocation in this proceeding. Pursuant to the terms of the Settlement Agreement, as soon as practicable following a Commission decision adopting the Settlement Agreement, but no earlier than January 1, 2013, SCE will adjust its rates for all of its bundled-service and direct access (DA) customers.

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[1] Southern California Edison Company (SCE); The Utility Reform Network (TURN); the Division of Ratepayer Advocates (DRA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); Federal Executive Agencies (FEA); California Black Chamber of Commerce (CBCC); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); California City-County Street Light Association (CAL-SLA); Coalition for Affordable Street Lights (CASL); Solar Energy Industries Association (SEIA); County of Los Angeles (LAC); Direct Access Customer Coalition (DACC) and Energy Producers and Users Coalition (EPUC) are collectively referred to herein as the Settling Parties. Pursuant to Rule 1.8(d), SCE has been authorized to file this motion on behalf of the Settling Parties. Wal-Mart Stores, Inc. & Sam's West, Inc., (Wal-Mart) are not signatories to, but do not oppose, either the Settlement Agreement or this motion.

Section I of this motion provides background related to this proceeding. Section II describes in general the positions advocated by parties in this proceeding and the terms of the Settlement Agreement. Section III 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 IV discusses the requests of the Settling Parties related to processing of this request and the implementation of revised rates.

I.
BACKGROUND

This proceeding was initiated by the filing of SCE's application on June 6, 2011, along with SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design. On October 7, 2011, SCE revised its initial testimony, primarily to remove its initial proposal to increase SCE's current residential customer charge.[2] DRA served its initial testimony on December 20, 2011. Intervening parties, including TURN, CFBF, AECA, FEA, CBCC; CMTA, CLECA, EUF, CAL-SLA, CASL, SEIA, LAC, Wal-Mart, DACC, and EPUC, served their initial testimony on February 6, 2012. The Settling Parties represent every spectrum of customer interests. Each represents customers or groups of customers who are directly affected and have an interest in the outcome 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 and an initial settlement conference was held on February 22, 2012. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference.

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2 The name used in SCE's tariffs for the residential customer charge is the Basic Charge.

II.

SUMMARY OF POSITIONS AND SETTLEMENT

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

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

- Marginal customer, demand, and generation cost components;
- Allocation of distribution and generation unbundled revenue requirements based on marginal cost components or in accord with prior Commission decisions; and
- Capping of allocated revenues to rate groups to promote rate stability while achieving movement toward cost-based rate structures.

The Settlement Agreement resolves all issues raised in this proceeding with respect to marginal costs and revenue allocation. Among other things, the Settlement Agreement provides the means of establishing rates 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

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[3] Capitalized terms are defined in Paragraph 3 of the Marginal Cost and Revenue Allocation Settlement Agreement.

SCE's total revenue requirement among the rate groups, thereby making moot the need to litigate and resolve the differences regarding marginal cost methodologies and forecasts.

The Settlement Agreement does not reflect the approval or acceptance of any of the Parties' marginal cost proposals. However, the Settling Parties agree that the designated marginal costs set forth in Paragraphs 4.a.i, ii, iii, and iv of the Settlement Agreement may be used for the purpose of establishing unit marginal costs that are used in SCE's revenue allocation and rate design model (SCE's Model) and, where applicable, to set floors and caps for energy, customer, or demand charges for certain customer classes.

B. Revenue Allocation

A number of issues were raised in prepared testimony regarding the allocation to rate groups of SCE's Commission-authorized distribution and generation revenue requirements. Parties 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. Other issues were raised with respect to how particular revenue requirements should be allocated among the rate groups, such as the revenue deficiency resulting from the discount provided to customers on the CARE program, costs for demand response and other public purpose programs, and SCE SmartConnect program costs.

In order to avoid further litigation and to mitigate potentially adverse impacts on any particular rate group based on movement toward 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 effective after a Commission decision adopting this Agreement has been rendered, based on a number of assumptions agreed to by the Settling Parties and reflected in SCE's Model. While no change to SCE's total system revenue requirement is requested in this proceeding, the Settling Parties agreed to establish a method to allocate revenues to each rate group based on agreed-upon marginal costs, methods of allocating revenues to each rate group, and a proxy for future revenue requirements. Because the level of SCE's authorized revenues and sales at the time this Agreement will be first implemented are presently unknown, this Agreement reflects an estimated 2013 consolidated SCE revenue requirement of $12,338 million, including revenues for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the California Solar Initiative (CSI), the DWR Bond Charge, and the New System Generation Charge (NSGC). The illustrative rates provided in Appendix B of this Agreement that are based on the estimated consolidated SCE revenue requirement will therefore 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 the Settlement Agreement.

The Settlement Agreement produces changes in average rates for bundled-service and DA customer rate groups based on the estimated consolidated revenue requirement, resulting in a bundled-service system average percentage increase of 10.3 percent in 2013 relative to June 2011, as illustrated in Table B-1.[4] To promote rate stability, the revenue allocations and illustrative average rates agreed to by the Settling Parties employ restrictions on delivery and generation revenue changes both above and below the system average percentage change (SAPC). The Settling Parties agreed to limit the assignment of revenues to rate groups by means of a sequential process, involving caps on delivery and generation revenues which are set forth in Table RA-6 and Paragraph 4.b.ii of the Settlement Agreement.

The results that are provided in Appendix B of the Settlement Agreement are subject to change based on the revenue requirement changes actually adopted in other decisions when this Agreement is first implemented. To the extent that actual revenue requirements change from these assumptions, the Settling Parties agree that such changes shall be reflected in the 2013 revenues and average rates listed in Appendix B in accordance with the process set forth in Paragraph 4.b.vi of the Settlement Agreement.

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[4] Average rate increases for DA customers are included in Table B-2, of Appendix B to the Settlement Agreement.

While tables in the Settlement Agreement, such as Table B-1, copied below, combine revenues or rates for the two Agricultural and Pumping rate groups, i.e., TOU-PA-2 and TOU-PA-3 (shown as “Total Ag & Pumping” in the tables), the allocation of revenues between those two rate groups and within rate schedules within those two Agricultural and Pumping rate groups will be addressed in a separate settlement agreement.

Table B-1
Bundled-Service Rate Groups
Comparison of June 2011 to Illustrative 2013 Settlement Rates[5]

	June 2011	Uncapped Rates	Proposed 2013 Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	15.6	17.7	17.5	13.4%	11.8%	110%	112%
GS-1	17.0	17.1	17.7	0.5%	4.3%	120%	114%
TC-1	15.3	16.4	16.7	7.2%	8.9%	108%	107%
GS-2	15.2	16.2	16.5	6.6%	9.0%	107%	106%
TOU-GS-3	13.2	15.3	15.0	15.7%	13.8%	93%	96%
Total LSMP	15.0	16.1	16.4	7.3%	9.0%	106%	105%
TOU-8-Sec	12.4	13.5	13.7	8.7%	10.5%	88%	88%
TOU-8-Pri	11.2	12.3	12.4	9.8%	10.6%	79%	79%
TOU-8-Sub	7.2	8.7	8.1	20.2%	12.3%	51%	52%
Total Large Power	10.8	12.0	12.0	10.9%	10.8%	76%	77%
Total Ag.&Pumping	11.9	12.7	12.9	7.4%	8.8%	84%	83%
Total Street Lighting	18.0	17.2	17.4	-4.5%	-3.1%	127%	111%
STANDBY/SEC	11.5	13.0	12.8	13.2%	11.0%	81%	82%
STANDBY/PRI	11.3	12.8	12.6	12.7%	11.0%	80%	80%
STANDBY/SUB	8.0	8.6	8.9	8.2%	11.0%	56%	57%
Total Standby	9.1	10.0	10.1	10.1%	11.0%	64%	65%
Total System	14.2	15.6	15.6	10.3%	10.3%	100%	100%

5 Illustrative rate levels for DA customers are provided in Table B-2, of Appendix B to the Settlement Agreement.

In order to produce unbundled 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, DWR bond charge, DA cost responsibility surcharge, nuclear decommissioning, and public purpose programs, etc.) shall be allocated to rate groups as specified in the Settlement Agreement in Paragraph 4.b.v, subparts 1 through 9.

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, except to the extent otherwise specified in the Settlement Agreement with respect to CSI and SGIP revenue requirements, energy efficiency shareholder incentives, and demand response program revenue requirements as set forth in Paragraph 4.b.vii, subparts 2 through 5.

III.

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 (Rules). The Settlement Agreement is 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 parties to reduce the risk that litigation will produce unacceptable results.[7] As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest it should be adopted without change.

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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.

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 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 prepared testimony of the Settling Parties contains sufficient information for the Commission to judge the reasonableness of the Settlement Agreement.

B. The Settlement Agreement Is Consistent With 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

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[8] *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360: "[S]ettlements brought to this Commission for review are not simply the resolution of private disputes, such as those that may be taken to a civil court. The public interest and the interest of ratepayers must also be taken into account and the Commission's duty is to protect those interests."

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. The Settlement Agreement is in the public interest and in the interest of SCE's customers. 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 other parties as well, so that they may focus on other proceedings. The prepared direct testimony contains sufficient information for the Commission to judge the reasonableness of the Settlement Agreement and for it to discharge any future regulatory obligations with respect to this matter.

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 which 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.

IV.

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, 2013. In order to accomplish this, the Settling Parties recommend 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 there are any material contested issues of fact, or questions from the Commission following the filing of comments, 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**
Motion filed for Adoption of the Settlement Agreement	July 27, 2012
Opening comments, if any, on the Settlement Agreement	August 27, 2012
Reply comments on the Settlement Agreement	September 11, 2012
Hearing on the Settlement Agreement, if necessary	September 20, 2012

V.

CONCLUSION

WHEREFORE, the Settling Parties respectfully request that the Assigned Commissioner, Assigned ALJ, 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.

Respectfully submitted,

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/s/ Bruce A. Reed

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And on behalf of Settling Parties[9]

July 27, 2012

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

Attachment A

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

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, Design Rates, and Implement Additional Dynamic Pricing Rates	)))))	Application 11-06-007 (Filed June 6, 2011)

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

July 25, 2012

LIMS 314-4348

MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

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MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

This Marginal Cost and Revenue Allocation Agreement (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); Division of Ratepayer Advocates (DRA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); Federal Executive Agencies (FEA); California Black Chamber of Commerce (CBCC); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); California City-County Street Light Association (CAL-SLA); Coalition for Affordable Street Lights (CASL); Solar Energy Industries Association (SEIA); County of Los Angeles (LAC); Direct Access Customer

Coalition (DACC) and Energy Producers and Users Coalition (EPUC); (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. DRA is a division of the Commission that represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with reliable and safe service levels. Pursuant to Public Utilities Code Section 309.5(a), the DRA is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

d. CBCC represents the interests of small businesses and micro-businesses in California, particularly African American-owned small businesses.

e. CFBF is a voluntary, private, non-profit corporation representing more than 74,000 members and over 80 percent of California's commercial agriculture.

f. AECA represents individual agricultural producers, processors, produce-cooling operations, agricultural water agencies and member agricultural associations, many of which are customers of SCE and Pacific Gas & Electric Company.

g. FEA represents the consumer interests of all Federal executive agencies that take utility service from Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company.

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[1] Wal-Mart Stores, Inc. & Sam’s West, Inc, (Wal-Mart) are not signatories to, but do not oppose, this Agreement.

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

i. CMTA is a trade association with over 500 members operating in the manufacturing and high technology sectors of the California economy. Many of its members receive electrical service from SCE either as bundled service or DA customers.

j. CLECA is an organization of large, high voltage and high load factor industrial customers of SCE and Pacific Gas and Electric Company, most of whom are served under interruptible tariff options.

k. CAL-SLA represents cities and counties that take street and area lighting and traffic signal services from SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company.

l. CASL is an *ad hoc* group of public agencies concerned about SCE's street light rates and services, consisting of the following participants: the cities of Moreno Valley, Downey, Huntington Beach, Murrieta, Redondo Beach, Rancho Cucamonga, Torrance, Upland, and Yorba Linda.

m. EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC, Chevron U.S.A. Inc., Phillips 66 Company, ExxonMobil Power and Gas Services, Shell Oil Products US, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

n. LAC has actively participated in numerous Commission proceedings over the past several years, including but not limited to: prior SCE general rate cases (GRCs), energy efficiency proceedings, and greenhouse gas rulemakings. Through prior SCE GRCs and the energy efficiency proceedings, LAC has sought to engage SCE to increase funding for, and improve the performance of, SCE's local government energy efficiency partnership programs. LAC maintains over 2,500 separately metered accounts.

o. SEIA is a non-profit organization with members throughout California and the country who want a rapid transition to a clean and renewable energy future.

p. Wal-Mart is a large commercial customer with approximately 83 stores and distribution centers taking delivery service from SCE. The generation portion of Wal-Mart's load is largely met through direct access and on-site renewable generation.

q. DACC is a regulatory alliance of commercial, industrial and governmental customers who have opted for direct access for some or all of their electric loads.

2. <u>Definitions</u>

Capitalized terms in this Agreement, whether in singular or plural, shall (i) if identified in parentheses, have the meaning given to such term in the body of this Agreement, or (ii) if unidentified in parentheses, have the following meanings:

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

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

e. "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. It consists of the DWR Bond Charge revenue requirement.

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

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

h. "Loss of Load Expectation" means the expectation that available generation capacity will be inadequate to supply customer demand at any given moment.

i. "Marginal Cost" means the change in total cost due to a small change in the quantity produced or provided.

j. "New System Generation Charge" is a cent per kWh charge included in SCE's delivery charges that recovers the revenues associated with facilities and resources that provide distribution grid stability from all bundled-service and DA customers, as authorized the Commission D.09-03-031 and by SCE Advice Letter 2346-E (May 29, 2009).

k. "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.

l. "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 are excluded from SCE's allocation of its revenue requirement to all other rate groups.

m. "Primary Voltage" means facilities at which electric power is taken or delivered, generally between 12 kV and 33 kV, but always between 2 kV and 50 kV.

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

o. "Real Economic Carrying Charge" or RECC means a measure of the per dollar savings of deferring an investment one year.

p. “Secondary Voltage” means facilities at which electric power is taken or delivered, generally between 120 volts and 480 volts, but always less than 2 kV.

q. “SGIP” means Self Generation Incentive Program.

r. “System Average Percentage Change” or SAPC 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, as defined in Paragraph 2.g, above, are implemented periodically when SCE’s authorized revenue requirements change after the initial implementation of this Agreement.

s. System Average Rate or SAR 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 or CPUC-approved level of sales.

t. “Settling Parties” means SCE, DRA, TURN, CFBF, AECA, FEA, CBCC, CMTA, CLECA, EUF, CAL-SLA, CASL, SEIA, LAC, DACC, and EPUC.

u. “Subtransmission Voltage” means facilities at which electric power is taken or delivered, generally greater than 50 kV and less than 220 kV.

v. “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.

3. Recitals

a. Paragraph 5.b.viii of SCE’s 2009 General Rate Case (GRC) Revenue Allocation Settlement Agreement, which was approved by Decision (D.)09-08-028, 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.09-08-028.[2]

b. In Phase 2 of SCE's 2012 GRC, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

c. On June 6, 2011, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 11-06-007. On October 7, 2011, SCE revised its initial testimony, primarily to remove its initial proposal to increase SCE's current residential Basic Charge.

d. DRA served its initial testimony on December 20, 2011. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on February 6, 2012.

e. The following Settling Parties submitted prepared testimony regarding marginal cost or revenue allocation: SCE, TURN, DRA, CFBF, AECA, FEA, EUF, CMTA, CLECA, CAL-SLA, CASL, SEIA, EPUC, LAC, CBCC, and DACC.

f. SCE provided notice to all parties of its intent to conduct a settlement conference related to issues and an initial settlement conference was held on February 22, 2012.

g. Continuing settlement discussions occurred among the parties after February 22, 2012.

h. 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 allocation of SCE's authorized revenue requirement beginning with the implementation of a CPUC

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2 See D.09-08-028, Attachment B, p. 16.

decision approving this Agreement, and have reached agreement as indicated in Paragraph 4 of this Agreement.

i. 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.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in this 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. 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 next GRC.

a. Marginal Costs

This Agreement does not reflect approval or acceptance of any of the Settling Parties' marginal cost proposals as the basis for this Agreement. The Settling Parties agree that it is reasonable to use the marginal costs set forth in Paragraphs 4.a.i, ii, and iii below for the purpose of establishing unit marginal costs that are used in SCE's revenue allocation and rate design model (SCE's Model) and, where applicable, to set floors and caps for energy, customer, or demand charges for certain customer classes.

i. Generation Marginal Energy Costs

Generation marginal energy costs incorporated in this Agreement shall be based on an average burner-tip natural gas price of $4.47 per million BTUs, based on monthly NYMEX Henry Hub futures prices from January 2012 through December 2014.[3] The hourly marginal energy costs derived from this gas price forecast are compiled by TOU periods using the model proposed by EPUC.[4] The resulting marginal energy costs are summarized in Table RA-1 below:

Table RA-1

Three Year Average (2012 through 2014)
Generation Marginal Energy Costs (2012 $)

	Summer TOU			**Winter TOU**		
Description	**On-Peak**	**Mid-Peak**	**Off-Peak**	**Mid-Peak**	**Off-Peak**	**Annual**
MEC ($/kWh)	0.05451	0.04228	0.02931	0.04583	0.03517	0.03850
Gas Price ($/MM Btu)						4.473

ii. Generation Marginal Capacity Costs

Generation marginal capacity cost shall be based on an estimated annualized deferral value of a gas-fired combustion turbine (CT), yielding a net generation marginal capacity cost of $114 per kW per year.[5] The generation marginal capacity cost is allocated to TOU periods by the relative loss of load expectation measure. Unless specified elsewhere, for purposes of the rate credits provided for non-firm service, including price-based and reliability-based demand

[3] EPUC, Testimony of Jim Ross, p. 24.
[4] EPUC, Testimony of Jim Ross, p. 27.
[5] To account for resource adequacy requirements, 15 percent is added to the generation marginal capacity revenue requirement for the purpose of revenue allocation in SCE's Model.

response programs, the net generation marginal capacity cost will be reduced by a 5.6 percent general plant loader, yielding a value of $107.6 per kW per year.

Generation marginal capacity costs by season and by time-of-use periods shall be as listed in Table RA-2 below:

Table RA-2
Generation Marginal Capacity Cost (2012$)
By TOU Period

	Summer				Winter	
	On-Peak	Mid-Peak	Off-Peak		Mid-Peak	Off-Peak
Marginal Generation Capacity $114/kW-year	79.91	23.37	1.03		9.23	0.46
Avoided Generation Capacity $107.6/kW-year	75.44	22.06	0.97		8.72	0.43
Relative Loss of Load Expectation[6]	70.1%	20.5%	0.9%		8.1%	0.4%
Note: These costs are established at the generator level.						

iii. Marginal Customer Costs

For purposes of revenue allocation only, marginal customer costs are determined based on a 50:50 ratio of SCE's RECC and SCE's NCO marginal customer costs calculations,[7] adjusted as follows: (1) use TURN's RECC input values[8] with the exception of taxes and A&G, and (2) set the NCO replacement factor at 3.1 percent, instead of 5.0 percent, based on a weighted average of estimated replacement rates for meters, service drops, and final line

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[6] Exhibit SCE-02 (Updated), Table I-12.
[7] Appendix E, SCE-02 (Updated), October 7, 2011
[8] Testimony of TURN, William Marcus, p. 4.

transformers. The resulting marginal customer costs shall be as listed in Table RA-3, below:

Table RA-3
Marginal Customer Costs

	Monthly NCO Customer Cost 2012$		Monthly RECC Customer Costs 2012$		50:50 NCO:RECC Monthly
Domestic	7.18		12.10		9.64
GS-1	10.30		17.63		13.96
TC-1	9.54		18.24		13.89
GS-2	63.01		139.91		101.46
TOU-GS-3	183.10		310.77		246.94
TOU-8					
TOU-8-Sec	225.88		428.85		327.36
TOU-8-Pri	134.26		224.73		179.50
TOU-8-Sub	631.95		1,488.82		1,060.38
TOU-8-Standby					
Standby-Sec	225.88		428.85		327.36
Standby-Pri	134.26		224.73		179.50
Standby-Sub	631.95		1,488.82		1,060.38
TOU-PA-2	41.84		92.82		67.33
TOU-PA-3	288.53		278.21		283.37
Street Lights	7.23		12.36		9.80

iv. Marginal Distribution Capacity Cost

For purposes of revenue allocation, marginal distribution costs shall be consistent with SCE's proposals in Exhibit SCE-02 (Updated) with adjustments, to provide the results listed in Table RA-4, below[9]:

Table RA-4
Distribution Marginal Cost (2012 $)

	System Design Demand ($/kW-year)
Non-ISO Subtransmission (66 kV)	34
Distribution (12 kV)	84

9 Design demands are consistent with SCE's proposals in Exhibit SCE-02, Table I-13, p. 30, with adjustments made to reflect SCE's current cost of capital, a corrected RECC escalation rate, and a 10-year historical regression for the design demand calculation instead of SCE's proposed 15-year regression.

b. Revenue Allocation

In order to avoid further litigation and to mitigate potentially adverse impacts on any particular rate group based on movement toward 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 effective after a Commission decision adopting this Agreement has been rendered, based on a number of assumptions reflected in SCE's Model.

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 sales at the time this Agreement will be implemented are presently unknown. Thus, this Agreement reflects an estimated consolidated SCE revenue requirement of $12,338 million in 2013, 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, and the New System Generation Charge (NSGC). The illustrative rates 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 first implemented pursuant to the provisions of this Agreement.

i. Estimated Consolidated Revenue Requirement

The 2013 estimated consolidated revenue requirement of $12,338 million includes the following significant revenue requirement assumptions:

- 50 percent of SCE's requested increase in 2012 GRC Phase 1 distribution and generation revenue requirements increase is approved by the CPUC;

- 50 percent of SCE's requested 2012 GRC Phase 1 attrition year increase for 2013 is approved by the CPUC;
- Base Transmission Revenue Requirement of $722 million less $91 million of transmission-related revenue credits for a total of $631 million;
- For 2013, eliminate the $336 million ERRA balancing account revenue overcollection that is presently reflected in SCE's 2012 rates;
- For 2013, eliminate the $441 million DWR Reserve Bond refund that is presently reflected in SCE's 2012 rates; and
- For 2013, reduce the Power Charge Indifference Amount (PCIA) and Competition Transition Charge (CTC) 2013 revenue requirement to 60 percent of the revenue requirement reflected in June 2011 rates recognizing the potential impact of a revised Market Price Benchmark (MPB) value on the PCIA and the CTC revenue requirements.[10]

Table RA-5, below, provides additional detail with respect to the assumed revenue requirements that are reflected in the 2013 estimated consolidated revenue requirement.

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10 See D.11-12-008, Resolution E-4475, and AL-2737-E.

Table RA-5
Comparison of June 2011 to Estimated 2013 Revenue Requirements

	June 2011 Revenue Requirements w/2012 SF			GRC Phase 2 - 2013 Scenario Revenue Requirements ($000)			% Change (June 2011 vs. GRC Phase 2 - 2013 Scenario)		
	Bundled Service	DA	Total Retail	Bundled Service	DA	Total Retail	Bundled Service	DA	Total Retail
Generation	**5,243,584**	**155,622**	**5,399,206**	**5,943,521**	**111,353**	**6,054,874**	**13%**	**-28%**	**12%**
New System Generation	**153,638**	**20,095**	**173,734**	**133,568**	**17,450**	**151,018**	**-13%**	**-13%**	**-13%**
Distribution	**3,647,979**	**273,629**	**3,921,608**	**4,181,087**	**343,194**	**4,524,281**	**15%**	**25%**	**15%**
Distribution O&M and Capital	3,411,992	252,592	3,664,584	3,973,149	321,349	4,294,498	16%	27%	17%
Self Generation/CA Solar Initiatives	127,448	13,002	140,451	124,503	15,097	139,599	-2%	16%	-1%
Other Distribution	18,909	1,400	20,309	(1,522)	(123)	(1,645)	-108%	-109%	-108%
Demand Response	66,748	4,941	71,690	84,958	6,871	91,829	27%	39%	28%
EE Incentive	22,881	1,694	24,575	0	0	0	-100%	-100%	-100%
Nuclear Decommissioning	**6,731**	**1,002**	**7,733**	**26,428**	**3,935**	**30,363**	**293%**	**293%**	**293%**
Public Purpose Programs	**628,469**	**73,656**	**702,125**	**473,777**	**57,360**	**531,138**	**-25%**	**-22%**	**-24%**
Energy Efficiency	416,628	48,828	465,457	411,241	49,789	461,030	-1%	2%	-1%
CARE Administration	5,014	588	5,602	4,949	599	5,549	-1%	2%	-1%
Other Public Purpose Programs	206,827	24,240	231,067	57,587	6,972	64,560	-72%	-71%	-72%
Transmission	**557,401**	**62,580**	**619,981**	**568,545**	**62,655**	**631,200**	**2%**	**0%**	**2%**
Trust Transfer Amount (TTA)	**0**	**0**	**0**	**0**	**0**	**0**	**-**	**-**	**-**
DWR Bond Charge	**338,653**	**56,190**	**394,843**	**338,652**	**56,190**	**394,843**	**0%**	**0%**	**0%**
PUCRF	**17,948**	**2,673**	**20,621**	**17,948**	**2,673**	**20,621**	**0%**	**0%**	**0%**
Total Revenue Requirement	**10,594,403**	**645,448**	**11,239,851**	**11,683,526**	**654,811**	**12,338,337**	**10.3%**	**1%**	**9.8%**

A number of significant unknowns could either increase or decrease the estimated revenue requirement when this Agreement is first implemented and applied to SCE's authorized revenues.[11] For bundled-service customers, the estimated consolidated revenue requirement used as a proxy in this Agreement represents a SAPC increase of 10.34 percent from the June 2011 rate levels to estimated 2013 rate levels, *i.e.,* from 14.2 ¢/kWh to 15.6 ¢/kWh, both based upon SCE's forecasted sales for 2012.[12]

ii. Limits 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 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 SAPC.

Except where otherwise specified, any undercollection or overcollection of SCE's authorized revenues from a particular rate group resulting from specified restrictions will be allocated based on the percentage of uncapped generation or distribution marginal cost revenues to the rate groups that are unaffected by the respective generation or distribution revenue limits. Table RA-6 and Paragraph 4.b.ii.subparts 1, 2, and 3, below, describe these restrictions and illustrate the results. Table RA-7, below, lists the functional

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[11] In addition, changes to residential rates may require some changes to the proposed allocations to other rate groups due to changes in the level of the CARE surcharge.

[12] See e.g., Exhibit SCE-02, Table II-19.

revenue allocator percentages that shall be used to allocate each unbundled revenue requirement to each rate group based on these principles.[13]

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[13] The tables in this Agreement list revenues or rates for the consolidated Agricultural and Pumping rates 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 Agreement. However, the allocation of revenues between the two rate groups is to be addressed separately in an Agricultural Rate Design Settlement Agreement.

Table RA-6
June 2011 Rates Compared To 2013 Settlement Rates
(Estimated Consolidated Revenue Requirement)

Retail Delivery Distribution Capping
Direct Access and Bundled-Service Customers

	June 2011 Retail Del Rate	Uncapped Retail Del Rate	Capped Retail Del Rate	Uncapped %	Capped %
Residential	8.31	8.85	8.92	6.41%	7.23%
GS-1	8.98	9.03	9.09	0.62%	1.20%
TC-1	10.15	10.16	10.16	0.10%	0.12%
GS-2	7.54	8.16	8.20	8.20%	8.81%
TOU-GS-3	6.40	7.01	7.04	9.45%	10.04%
Total LSMP	7.45	7.97	8.02	6.98%	7.58%
TOU-8-Sec	5.23	5.93	5.84	13.40%	11.58%
TOU-8-Pri	4.49	5.22	5.01	16.14%	11.58%
TOU-8-Sub	2.24	2.59	2.50	15.89%	11.58%
Total LP	4.15	4.76	4.63	14.62%	11.58%
Total Ag.&Pumping	6.04	5.94	5.97	-1.71%	-1.18%
Total StLights	13.62	12.90	12.89	-5.27%	-5.31%
STANDBY/SEC	4.62	5.94	5.27	28.44%	14.08%
STANDBY/PRI	4.75	6.27	5.42	31.86%	14.08%
STANDBY/SUB	2.42	2.67	2.67	10.17%	10.42%
Total Standby	3.19	3.84	3.58	20.49%	12.23%
System	6.80	7.31	7.31	7.58%	7.58%

All rate groups except Standby: SAR + 4% 11.58%
Standby (SEC, PRI): SAR + 6.5% 14.08%

1st Stage Generation Capping
Bundled-Service Customers

	June 2011 Total Rate	Capped Retail Del Rate	Capped Bundled Del Rate	Uncapped Generation Rate	Uncapped Total Rate	Capped Generation Rate	Capped Total Rate	Uncapped %	Capped %
Residential	15.62	8.92	8.91	8.88	17.79	8.56	17.47	13.9%	11.8%
GS-1	17.01	9.09	9.08	8.06	17.14	8.66	17.75	0.8%	4.3%
TC-1	15.30	10.16	10.17	6.23	16.40	6.50	16.67	7.2%	8.9%
GS-2	15.18	8.20	8.40	7.83	16.23	8.16	16.57	6.9%	9.1%
TOU-GS-3	13.19	7.04	7.45	7.84	15.29	7.50	14.95	16.0%	13.3%
Total LSMP	15.03	8.02	8.30	7.87	16.17	8.09	16.39	7.6%	9.0%
TOU-8-Sec	12.45	5.84	5.95	7.48	13.43	7.80	13.75	7.9%	10.5%
TOU-8-Pri	11.20	5.01	5.07	7.02	12.09	7.32	12.39	7.9%	10.6%
TOU-8-Sub	7.20	2.50	2.55	6.01	8.55	5.54	8.09	18.8%	12.3%
Total LP	10.81	4.63	4.87	6.99	11.86	7.11	11.98	9.7%	10.8%
Total Ag.&Pumping	11.85	5.97	6.02	6.74	12.76	6.88	12.90	7.7%	8.8%
Total StLights	17.99	12.89	13.11	4.04	17.15	4.33	17.44	-4.7%	-3.1%
STANDBY/SEC	11.52	5.27	5.33	7.04	12.36	7.46	12.79	7.3%	11.0%
STANDBY/PRI	11.33	5.42	5.26	6.70	11.96	7.31	12.58	5.5%	11.0%
STANDBY/SUB	7.98	2.67	2.64	6.00	8.64	6.22	8.86	8.3%	11.0%
Total Standby	9.12	3.58	3.53	6.26	9.79	6.60	10.13	7.3%	11.0%
System	14.17	7.31	7.68	7.95	15.63	7.95	15.63	10.3%	10.3%

All (with below exceptions): SAR + 1.5% 11.85%
GS-1: SAR - 6% 4.35%
TOU-GS-3: SAR + 3% 13.35%
TOU-8-SUB: SAR + 2% 12.35%
AG: SAR - 1.5% 8.85%
Standby: SAR + 0.66% 11.00%
Street Light Floor (excludes Non-Allocated): SAR - 6% 4.35%

2nd Stage Generation Capping
Bundled-Service Customers

	Capped Total Rate	Capped %
Residential	17.47	11.8%
GS-1	17.75	4.3%
TC-1	16.67	8.9%
GS-2	16.54	9.0%
TOU-GS-3	15.01	13.8%
Total LSMP	16.39	9.0%
TOU-8-Sec	13.75	10.5%
TOU-8-Pri	12.39	10.6%
TOU-8-Sub	8.09	12.3%
Total LP	11.98	10.8%
Total Ag.&Pumping	12.90	8.8%
Total StLights	17.43	-3.1%
STANDBY/SEC	12.79	11.0%
STANDBY/PRI	12.58	11.0%
STANDBY/SUB	8.86	11.0%
Total Standby	10.13	11.0%
System	15.63	10.3%

GS-1: SAR - 6% 4.35%
TOU-GS-3: SAR +3.5% 13.85%
GS-2 Set residually

Table RA-7
Summary of Functional Revenue Allocators

	Uncapped	Capped	Uncapped	Capped					
	Distribution		Generation		APS & Interruptible Surcharge[1]	CSI/SGIP[2]	PPP[3]	NDC/PUCRF[4]	NSGC[5]
Total Domestic	49.6%	50.0%	42.0%	40.6%	37.8%	32.7%	37.3%	32.9%	36.5%
GS-1	6.7%	6.8%	6.6%	7.1%	6.0%	7.7%	7.1%	5.7%	6.9%
TC-1	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
GS-2	19.6%	19.8%	19.6%	20.3%	19.1%	22.5%	20.7%	19.1%	20.3%
TOU-GS-3	8.4%	8.4%	8.4%	8.1%	9.7%	10.2%	9.4%	10.0%	9.9%
Total LSMP	34.8%	35.1%	34.6%	35.6%	34.8%	40.4%	37.3%	34.9%	37.1%
TOU-8-Sec	6.8%	6.6%	8.4%	8.7%	9.6%	10.2%	9.4%	10.4%	10.0%
TOU-8-Pri	3.8%	3.6%	4.7%	4.9%	5.8%	6.0%	5.6%	6.7%	5.7%
TOU-8-Sub	1.1%	0.9%	3.7%	3.5%	5.5%	4.3%	3.9%	7.1%	5.0%
Total Large Power	11.7%	11.1%	16.8%	17.1%	20.9%	20.4%	18.8%	24.2%	20.7%
Total Ag.&Pumping	2.6%	2.7%	3.5%	3.6%	3.3%	3.5%	3.2%	3.7%	2.8%
Total Street Lighting	0.1%	0.1%	0.5%	0.5%	0.5%	0.5%	1.1%	0.9%	0.5%
STANDBY/SEC	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.2%
STANDBY/PRI	0.6%	0.5%	0.7%	0.7%	0.8%	0.8%	0.7%	0.8%	0.7%
STANDBY/SUB	0.3%	0.3%	1.6%	1.6%	1.7%	1.4%	1.3%	2.2%	1.4%
Total Standby	1.1%	0.9%	2.5%	2.6%	2.7%	2.4%	2.3%	3.4%	2.4%
Total System	**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 and SGIP are allocated in proportion to each group's share of system revenues (bundled-service and DA), excluding CARE, FERA, and Streetlight Non-Allocated Revenues, with generation revenues for DA customers imputed as bundled-service customers

[3] PPP revenues are allocated in proportion to each group's share of system revenues (bundled-service and DA), with generation revenues for DA customers imputed as bundled customers

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

[5] 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

1. **Delivery Service Capping of Allocated Revenues (Affects Direct Access and Bundled-Service Customers)**

   As indicated in Table RA-6, above, based on the estimated consolidated revenue requirement, the increase to SCE's delivery service from the June 2011 system average rate (SAR) to the Settlement 2013 SAR would be 7.58 percent. The Settling Parties agree to cap delivery service revenues allocated to the rate groups, with the exception of Standby Secondary and Primary service rate groups, at the SAR increase for delivery services plus 4.0 percent. Standby Secondary and Primary service rate groups shall be capped at the SAR increase for delivery services plus 6.5 percent.

2. **First Stage Capping Of Generation Revenues On Bundled-Service Rates (Affects Bundled-Service Customers Only)**

   Based on the estimated consolidated revenue requirement, the increase to SCE's SAR for bundled-service delivery and generation service from the June 2011 SAR to the 2013 Settlement rates would be 10.34 percent. The Settling Parties agree to cap generation revenues such that the bundled-service increase for most rate groups is limited to the SAR increase plus 1.5 percent, or 11.84 percent based on the estimated 10.34 percent SAR increase. Other limits agreed to are as follows: GS-1 and Street Light (allocated revenues), SAR minus 6 percent; TOU-GS-3, SAR plus 3 percent; TOU-8-Sub, SAR plus 2 percent; Agricultural and Pumping, SAR minus 1.5 percent; Standby, SAR plus 0.66 percent.

3. **Second Stage Capping of Generation Revenues on Bundled-Service Rates (Affects GS-2 and TOU-GS-3 Rate Groups Only)**

   As a final adjustment to the revenues allocated to the GS-2 and TOU-GS-3 rate groups, not affecting any other rate groups, the Settling Parties agree to cap the TOU-GS-3 rate group at an increase of SAR plus 3.5 percent, or 13.84 percent based on the estimated 10.34 percent SAR increase, with the GS-2 rate group increase set residually with a revenue decrease commensurate with the revenue increase resulting from capping the TOU-GS-3 rate group at SAR plus 3.5 percent, instead of SAR plus 3.0 percent, as specified in Paragraph 4.b.ii.2, above. The GS-1 rate group remains limited at the SAR percentage change percent minus 6 percent.

iii. **Establishment Of Street Light Rate Group Non-Allocated Revenues**

The Settling Parties agree that Non-Allocated Revenues specifically assigned to the Street Light rate group, should be established at a level of $76.121 million and will not change from that level until rates resulting from SCE's next GRC Phase 2 proceeding are implemented, as specified in the Street Light and Traffic Control Rate Group Settlement Agreement.

iv. **Allocation Of CPUC And FERC-Authorized Revenue Requirements**

The Settling Parties agree that all of SCE's CPUC- and FERC-jurisdictional revenue requirements as reflected in the estimated consolidated revenue requirement shall be allocated as specified in Paragraph 4.b.v, 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.vi, 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 first implemented. Revenue changes and illustrative rates for both bundled-service and DA customers based on the estimated consolidated revenue requirement are also shown in Appendix B.

v. **Unbundled Revenue Requirements**

Without effecting any change to this Agreement and the illustrative rates provided in Appendix B, SCE's authorized unbundled revenue requirements shall be allocated to rate groups as follows:

1. **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-month system coincident peak (12-CP) revenue allocators shown in Table RA-7. FERC-jurisdictional rate components shall be added to the CPUC-jurisdictional delivery rates, resulting in total delivery service rates.

2. **Distribution-Related Revenue Requirement**

   a) Subject to the capping stages described in Paragraph 4.b.ii subparts 1, 2, and 3, above, as shown in Table RA-6, above, SCE's distribution revenue requirement reflected in the estimated consolidated revenue requirement shown in Table RA-5 shall be allocated to rate groups based on the applicable distribution functional allocators shown in Table RA-7.

   b) 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. Credits will reflect a capacity value of $107.6/kW-year, except for the SDP program and residential PTR rate options, whose credits shall remain at present levels which are established in other CPUC proceedings or in the Residential Rate Design Settlement Agreement.[14] These costs shall be allocated to rate groups for recovery in distribution rates from bundled-service and DA customers based on the generation allocators shown in Table RA-7.

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

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

3. **SCE Generation Revenue Requirement**

Subject to the capping stages described in Paragraph 4.b.ii subparts 1, 2, and 3, above, and as shown in Table RA-6, above, the generation revenue requirement reflected in the estimated consolidated generation revenue requirement, net of contributions, *e.g.* PCIA, from DA customers, shall be

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[14] SDP credits were most recently established in D.11-11-002.

allocated to rate groups based on the generation functional allocators shown in Table RA-7, above.

4. **DWR Bond Charge Revenue Requirement**

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, excluding CARE customers.

5. **Nuclear Decommissioning Revenue Requirement**

In accordance with D. 00-06-034, SCE's CPUC-jurisdictional, nuclear decommissioning revenue requirement shall be allocated to all rate groups, based on energy consumption reflecting total retail sales as indicated in Table RA-7, above, and shall be recovered as a cents per kilowatt-hour charge designated in SCE's tariffs as the NDC.

6. **Public Purpose Programs (PPP) Revenue Requirement**

SCE's non-CARE PPP revenue requirement shall be allocated based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA 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 cents per kWh basis.

7. **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 DA 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.

8. **CSI and SGIP Revenue Requirements**

The CSI and SGIP revenue requirements that are reflected in the estimated consolidated revenue requirement (Table RA-5) shall be allocated to rate groups based on the CSI/SGIP revenue allocator listed in Table RA-7, which is based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA customers imputed as if they were bundled-service customers, but excludes CARE and FERA revenues, as well as Street Light Non-Allocated Revenues. The CSI and SGIP revenue requirements will be recovered in rates on a cent per kWh basis in the distribution component of SCE's delivery charges, exempting CARE customers.

9. **Edison SmartConnect Cost Allocation**

Edison SmartConnect costs shall be allocated as distribution costs using the distribution functional allocators in Table RA-7.

10. New System Generation Revenue Requirement

The NSG revenue requirement shall be allocated using the 12-month system coincident peak (12-CP) revenue allocators shown in Table RA-7.

vi. **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 $12,338 million as described in Paragraph 4.b.i, above. To the extent SCE's actual authorized revenue requirement varies from this total when this Agreement is first implemented, the following process will be used:

- Using the estimated consolidated revenue requirement, adjust sales to reflect SCE's forecast of sales derived from the most recent approved Energy Resource Recovery Account (ERRA) forecast proceeding, using billing determinants derived from overall bundled-service and DA 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, delivery and generation capping, allocation of SGIP, CSI and other revenue requirements that are reflected in this Agreement and any updated FERC 12CP transmission factors, if necessary.
- After removing Street Light rate group Non-Allocated Revenues, develop the revised, capped functional revenue allocators; and
- To complete the revenue allocation process, apply the revised capped functional distribution and generation revenue allocators to the revised CPUC-authorized revenue requirements, add the FERC-authorized revenue requirements, 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.

The Settling Parties agree that SCE shall provide such changes relative to the estimated consolidated revenue requirement to the assigned ALJ, the Commission, and the Settling Parties if such changes occur prior to the issuance of a Commission decision adopting this Agreement.

vii. **Future Changes To SCE's Consolidated Revenue Requirement**

1. **Future Distribution and Generation Revenue Changes**

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

For rate changes resulting from attrition year revenue changes associated with SCE's ERRA or GRC, SCE will first adjust the rate levels for the default rate schedules, *e.g.*, Schedule D or Schedule TOU-8-Sec-B, using a functional SAPC adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between default rate schedule and the optional rate schedules. For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement would be allocated by applying a generation-level SAPC scalar based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis.

2. **Future CSI and SGIP Revenue Requirement Changes**

Notwithstanding Paragraph 4.b.vii, subpart 1, above, after this Agreement is first implemented, whenever SCE's authorized revenue requirements change, the authorized CSI and SGIP revenue requirements shall be allocated using the CSI/SGIP revenue allocator listed in Table RA-7, which reflects each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA customers imputed as if they were bundled-service customers, but excludes CARE and FERA revenues, as well as Street Light Non-Allocated Revenues. For future CSI and SGIP revenue changes, the difference between the CSI and SGIP revenues reflected in the estimated consolidated revenue requirement ($139.5 million shown in Table RA-5) and future authorized revenue requirements will be allocated using this methodology.

3. **Future Energy Efficiency Shareholder Incentives**

When this Agreement is first implemented, any energy efficiency shareholder incentives included in rates will be allocated to rate groups based on each rate group's proportional share of system revenues, with generation revenues for DA customers imputed as if they were bundled-service customers, with the results subject to the applicable distribution and bundled-service caps provided in this Agreement. For future revenue allocations after this Agreement is first implemented, the entire shareholder incentive revenue requirement (not just the change in revenue requirement) shall be allocated based on each rate group's proportional share of system revenues, with generation revenues for DA customers imputed as if they were bundled-service customers, given that there was no energy efficiency shareholder incentive revenue requirement reflected in the estimated consolidated revenue requirement upon which this Agreement is based.

4. **Future Demand Response Revenue Requirement Changes**

Notwithstanding Paragraph 4.b.vii, subpart 1, above,

a. Unless the CPUC directs a change to the allocation of demand response program revenue requirements in a future proceeding, the uncapped 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 revenue requirement will be allocated by each rate group's proportional share of system revenues, with generation revenues for DA customers imputed as if they were bundled-service customers, and the remaining 50 percent of the demand response revenue requirement will be allocated by the uncapped distribution revenue allocators in Table RA-7.

b. If the CPUC directs changes to the allocation of demand response program revenue requirements in a future proceeding, such revenue requirements will thereafter be allocated separately from other distribution revenue requirement changes using whatever allocation method is directed by the Commission, with the remaining distribution revenue requirement changes, with the exception of EE Shareholder incentives, SGIP and CSI revenue requirements, continuing to be allocated by the capped distribution allocation factors shown in Table RA-7, without modification.

5. Implementation Of Agreement

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Agreement as soon as practicable following the issuance of a final Commission decision approving this Agreement, but no earlier than January 1, 2013.

6. Record Evidence

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

7. 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. 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.

8. Signature Date

This 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 pledge support for Commission approval 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 2012 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.

10. Compromise Of Disputed Claims

This Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this 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 Agreement is reasonable, consistent with law and in the public interest.

11. Non Precedent

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, except as expressly provided in this Agreement or unless the Commission expressly provides otherwise.

12. Previous Communication

The Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Settling Parties. In the event there is any conflict between the terms and scope of the Agreement and the terms and scope of the accompanying joint motion, the Agreement shall govern.

13. Non Waiver

None of the provisions of this 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 Agreement or to 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 Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. Governing Law

This 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 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 Settling Party.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: July 25, 2012

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Joseph P. Como

Title: Acting Director Date: July 26, 2012

THE UTILITY REFORM NETWORK

By: /s/ Hayley Goodson

Title: Staff Attorney Date: July 25, 2012

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Karen Norene Mills

Title: Associate Counsel Date: July 25, 2012

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

By: /s/ Michael Boccadoro

Title: Executive Director Date: July 25, 2012

FEDERAL EXECUTIVE AGENCIES

By: /s/ Norman Furuta

Title: Associate Counsel Date: July 25, 2012

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ Dorothy Rothrock

Title: Vice President Date: July 25, 2012

CALIFORNIA BLACK CHAMBER OF COMMERCE

By: /s/ Tara Kaushik

Title: Attorney Date: July 25, 2012

ENERGY USERS FORUM

By: /s/ Carolyn Kehrein

Title: Consultant Date: July 25, 2012

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ William Booth

Title: Attorney Date: July 25, 2012

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ Reed Schmidt

Title: Consultant Date: July 25, 2012

COALITION FOR AFFORDABLE STREET LIGHTS

By: /s/ Scott Blaising

Title: Attorney Date: July 25, 2012

SOLAR ENERGY INDUSTRIES ASSOCIATION

By: /s/ Tom Beach

Title: Consultant Date: July 26, 2012

COUNTY OF LOS ANGELES

By: /s/ Tara Kaushik

Title: Attorney Date: July 25, 2012

ENERGY PRODUCERS AND USERS COALITION

By: /s/ Nora Sheriff

Title: Counsel Date: July 25, 2012

DIRECT ACCESS CUSTOMER COALITION

By: /s/ Dan Douglass

Title: Attorney Date: July 25, 2012

Appendix A

Comparison Of Positions And Settlement

MARGINAL COST COMPARISON EXHIBIT

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	EPUC	FEA	CFBF	AECA	SEIA	Settlement
Gas Price (all shown in $/MMBTU)	$5.36	$6.24	No position	No position	$4.40	$4.47	SCE's natural gas price should be updated to reflect lower market prices	$5.36	No position	$4.28	$4.47, adjusted to the generator burner tip, based on monthly NYMEX Henry Hub futures prices from January 2012 through December 2014.
Marginal Energy Costs (all shown in ¢ per kWh)	Annual average 4.94 based on production cost simulation mode, with greenhouse gas (GHG) adder.	DRA accepts shape of SCE's MECs	Use SCE's MECs, but add the cost of ancillary services and adjust for the higher cost of renewables (sum of about 0.64 cents per kWh)	No position	Supports the use of production cost model, with no GHG adder for 2012. TOU shaping should be based on average of SCE proposed ratios and CAISO day-ahead pricing information.	Use more recent NYMEX natural gas prices and other publicly available data. Base TOU ratios on historic ISO price data.	SCE's time differentiated MECs should be reduced by 20% to reflect lower natural gas and wholesale energy prices.	Annual average 4.94 based on production cost simulation mode, with GHG adder.	Energy costs should include capacity value in peak load periods.	Annual average 3.81, based on forecast of the average TOU market prices in the CAISO SP-15 market zone for 2012-2014. TOU factors based TOU profile of day-ahead SP-15 market prices in 2011.	Use SCE production cost model, but use $4.47/MMBTU gas price and model proposed by EPUC to spread costs to TOU periods. See Table RA-1 for results by TOU periods.
Marginal Customer Costs	RECC	NCO	NCO	No position	RECC	No position	RECC	RECC	Growth-based marginal costs (detail in testimony)	No position	50:50 ratio of SCE's RECC and SCE's NCO marginal customer cost calculations adjusted to use TURN's RECC input values with the exception of taxes and A&G, and the NCO replacement factor is set at 3.1 percent
Marginal Generation Capacity Costs (shown in $/kW-year)	$125, but $143 including a 15% Resource Adequacy (RA) Adder	$98, including a 15% RA Adder	$73	Agree with DRA. MGCC should reflect little to no need for new capacity next several years, and should include a component to account for the cost of providing resource adequacy.	$144	$157	$157	$143	No position	$174	$114, with 15% RA Adder
Avoided Cost Proxy	$118.5/kW-year	No position	No position	No position	No position	No position	No position	No Position	No position	No position	$107.6/kw-year

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	EPUC	FEA	CFBF	AECA	SEIA	Settlement
Design Demand (shown as $/kW-year)	$91 distribution, $35 subtransmission, using 15 years historical for investments and 5 years' forecast	$113 distribution, $41 subtransmission, using 10 years' historical data	$106 $38 [15]	No position	Supports SCE	No position	Supports SCE	Supports SCE	Growth-based marginal costs	No position	$84 distribution $34 subtransmission, based on 10 years of historical data

[15] See Testimony of Marcus, TURN, pp. 29-30. In addition, it is TURN's position that a scalar adding approximately 36% to demand distribution costs should be applied for revenue allocation to reflect that there are different numbers of kW of demand used to compute these quantities than the sum of the number of kW for each customer class. Testimony of Marcus, TURN, pp. 45-46.

REVENUE ALLOCATION COMPARISON EXHIBIT[16]

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	FEA	EUF	Settlement
Distribution Revenues	Allocate by marginal cost-based distribution allocator factor, after removing non-allocated revenues , includes EE, DR	Allocate by distribution allocation factor derived by EPMC	Non-CARE PPP – use EPMC for generation with DA imputed except as indicated for specified PPP components. This applies to EE (including shareholder incentives for EE), DR, 30% of AMI, Interruptible rates	No position	Supports SCE's proposal to use distribution allocator.			Allocate by distribution allocator factor, after removing non-allocated revenues, including EE, DR.
Generation Revenues	Allocate by marginal cost-based generation allocation factor derived by generation marginal cost revenue responsibility	Allocate by generation allocation factor derived by EPMC		No position	Supports SCE's proposal to allocate costs by generation allocator factor.			Allocate by generation allocation factor derived by generation marginal cost revenue responsibility

16 Positions taken by CAL-SLA and CASL on revenue allocation and Non-Allocated Revenues are discussed in the Street Light and Traffic Control Settlement Agreement, filed on June 29, 2012.

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	FEA	EUF	Settlement
Demand Response Programs	Allocate by distribution allocator factor	Allocate by system total revenue allocator	Generation allocator with DA	No position	Supports SCE's approach		Costs should not be allocated to direct access and community choice aggregation customers	For future revenue changes after Agreement first implemented, 50% of DR revenue requirement allocated on the basis of uncapped distribution revenue allocator, 50% on the basis of percentage of system average revenues (SAPC)
Nuclear Decommissioning	Allocate to all rate groups on equal ¢/kWh	N/A	N/A	N/A	N/A	N/A	N/A	Allocate to all rate groups on equal ¢/kWh
Public Purpose Program (General)	Allocate by system average percent of total system revenues, excluding CARE balancing account revenues	Allocate to all customer classes on equal ¢/kWh basis	Non-CARE PPP – EPMC generation with DA, so applies to EE. DR, pensions and benefits for PPP	No position	PPP costs, other than CARE costs, should be allocated on an SAPC basis	Support SCE's approach	Allocate to each rate group based on SAPC basis	Allocate by system average percent of total system revenues, excluding CARE balancing account revenues
CARE Balancing Account Revenues	Allocate based on each rate groups percentage of total energy sales, excluding exempt customers. Allocated to rate groups on an equal cents per kWh basis including DA sales, but excluding the kWh usage of CARE and Street and Area Lighting customers	Allocate to all customer classes on equal cents per kWh basis	Allocate to all customer classes on equal cents per kWh basis, excluding CARE and streetlights	No position	Allocate on an equal cents-per-kWh basis consistent with SB 695 requirements		Allocate to all customer classes on equal cents per kWh basis	Allocated to rate groups on an equal cents per kWh basis including DA sales, but excluding the kWh usage of CARE and Street and Area Lighting customers

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	FEA	EUF	Settlement
CSI Revenues	Allocate based on each rate group's proportion of SAPC revenues, excluding CARE, FERA, and streetlight facilities	Allocate to all rate groups on equal cents per kWh	CARE allocator, on equal cents per kWh except to CARE and streetlight customers	No position	Does not oppose SCE's use of the allocator SAPC by revenue for CSI. Opposes DRA proposal to allocate on equal cents per kWh basis.	Supports SCE's approach	Allocate to each rate group based on each rate group's proportion of system average percent change (SAPC) revenues	Allocate based on each rate group's proportion of SAP revenues, excluding CARE, FERA, and streetlight facilities
SGIP Revenues	Allocate by distribution allocator factor	Allocate to all rate groups on equal ¢/kWh	CARE allocator, alleges prohibited from any allocation to CARE customers	No position	Does not oppose the use of distribution revenue allocator, but could support the use of SAPC instead. Opposes DRA proposal to allocate on equal ¢/kWh basis.	Supports SCE's approach		Allocate based on each rate group's proportion of SAP revenues, excluding CARE, FERA, and streetlight facilities
SmartConnect Revenues	Allocate by distribution allocator factor	Allocate by system total revenue allocator	Allocate by generation allocator, include DA	No position	Allocate by distribution allocator factor	Allocate by distribution allocator factor		Allocate by distribution allocator

Issue	SCE	DRA	TURN	CBCC/LAC	CLECA/CMTA	FEA	EUF	Settlement
Capping[17]	Not proposed	Limit increases to 5% above system average percentage change (SAPC)	4% general rate cap, but treat the Ag rate groups as a single class. A floor should also apply so no class receives more than 8% less than the system average.	No cap, or alternatively 10%	Limit increases to SAPC plus 3%			Delivery cap of SAPC+4%; Generation cap of SAPC + 1.5%. Bundled ag rate groups treated as a single class for capping with a compromise allocation approximately midway between Edison's proposal of two separate classes (one capped, one uncapped) and TURN's proposal of a single class. Ag rates for subclasses to be determined in Ag Rate Design Settlement. All standby classes set at 11% bundled increase because of anomalies in capping process (because of distribution caps, standby voltage levels farthest below cost of service would receive lower increases than the voltage level closest to cost). Rate floor of 6% less than system average adopted (applies to GS-1 and to streetlights excluding facilities charges). (See Table RA-6 for details)

[17] WalMart supported separate caps for distribution and generation if capping is adopted. AECA proposed that Ag and Pumping rates should be capped at 0% above SAPC.

Appendix B

Revenue Allocation Summary Results

Table B-1

Bundled-Service Rate Groups

Comparison of June 2011 to Illustrative 2013 Settlement Rates

	June 2011	Uncapped Rates	Proposed 2013 Settlement Rates	Relative Percentage Change		Percent of System Average Rate	
	A	B	C	B/A	C/A	A	C
Total Domestic	15.6	17.7	17.5	13.4%	11.8%	110%	112%
GS-1	17.0	17.1	17.7	0.5%	4.3%	120%	114%
TC-1	15.3	16.4	16.7	7.2%	8.9%	108%	107%
GS-2	15.2	16.2	16.5	6.6%	9.0%	107%	106%
TOU-GS-3	13.2	15.3	15.0	15.7%	13.8%	93%	96%
Total LSMP	15.0	16.1	16.4	7.3%	9.0%	106%	105%
TOU-8-Sec	12.4	13.5	13.7	8.7%	10.5%	88%	88%
TOU-8-Pri	11.2	12.3	12.4	9.8%	10.6%	79%	79%
TOU-8-Sub	7.2	8.7	8.1	20.2%	12.3%	51%	52%
Total Large Power	10.8	12.0	12.0	10.9%	10.8%	76%	77%
Total Ag.&Pumping	11.9	12.7	12.9	7.4%	8.8%	84%	83%
Total Street Lighting	18.0	17.2	17.4	-4.5%	-3.1%	127%	111%
STANDBY/SEC	11.5	13.0	12.8	13.2%	11.0%	81%	82%
STANDBY/PRI	11.3	12.8	12.6	12.7%	11.0%	80%	80%
STANDBY/SUB	8.0	8.6	8.9	8.2%	11.0%	56%	57%
Total Standby	9.1	10.0	10.1	10.1%	11.0%	64%	65%
Total System	14.2	15.6	15.6	10.3%	10.3%	100%	100%

Table B-2

Direct Access Rate Groups

Comparison of June 2011 to Illustrative 2013 Delivery Service Settlement Rates[18]

	June 2011	Proposed 2013 Settlement Rates	Percent Change
Total Domestic	9.24	9.75	5.4%
GS-1	9.30	9.42	1.3%
TC-1	9.81	9.83	0.1%
GS-2	5.81	6.21	6.7%
TOU-GS-3	5.42	5.87	8.3%
Total LSMP	5.64	6.06	7.5%
TOU-8-Sec	4.95	5.51	11.4%
TOU-8-Pri	4.37	4.89	11.7%
TOU-8-Sub	2.18	2.43	11.5%
Total Large Power	3.70	4.13	11.5%
Total Ag.&Pumping	4.44	4.44	0.0%
Total Street Lighting	6.50	6.00	-7.7%
STANDBY/SEC	4.43	5.02	13.3%
STANDBY/PRI	5.39	6.19	14.8%
STANDBY/SUB	2.54	2.79	10.0%
Total Standby	3.38	3.79	12.2%
Total System	4.40	4.82	**9.5%**

18 Excludes PCIA, CTC, and DWRBC revenues in June 2011 and proposed 2013 Settlement rates.

Table B-3

Proposed Bundled Service Revenues

Adjusted Consolidated Revenue Requirement ($MM)

(Illustrative)

	Transmission	Distribution	Other	Total Delivery	Generation	Total Bundled
Total Domestic	224.6	1,881.9	408.8	2,515.3	2,415.8	4,931.1
GS-1	41.7	314.3	86.2	442.3	421.9	864.1
TC-1	0.3	5.3	1.1	6.8	4.3	11.1
GS-2	128.3	872.1	250.0	1,250.5	1,210.3	2,460.8
TOU-GS-3	52.1	323.2	101.5	476.9	484.0	960.8
Total LSMP	222.4	1,515.1	438.9	2,176.4	2,120.5	4,296.9
TOU-8-Sec	47.9	244.7	104.6	397.2	521.0	918.2
TOU-8-Pri	24.3	117.6	60.6	202.6	292.2	494.8
TOU-8-Sub	17.7	23.8	46.8	88.3	192.0	280.3
Total Large Power	89.9	386.1	212.1	688.1	1,005.2	1,693.3
Total Ag.&Pumping	16.8	123.2	48.0	188.0	214.8	402.8
Total Street Lighting	2.4	83.7	10.0	96.1	31.7	127.8
STANDBY/SEC	1.2	6.1	2.9	10.2	14.4	24.6
STANDBY/PRI	3.4	19.0	9.2	31.6	43.9	75.5
STANDBY/SUB	7.9	12.0	21.5	41.3	97.2	138.6
Total Standby	12.5	37.1	33.6	83.2	155.5	238.7
Total System	**568.5**	**4,027.1**	**1,151.4**	**5,747.0**	**5,943.5**	**11,690.5**

In contrast to the total bundled-service revenues in Table RA-5, the total bundled-service revenues in shown in the "Total Bundled" column of Table B-3 reflect the output of SCE's Model, including capping and redistribution of revenues associated with the CARE surcharge.

Table B-4

Proposed DA Service Revenues

Adjusted Consolidated Revenue Requirement ($MM)

(Illustrative)

	Transmission	Distribution	Other	Total Delivery	PCIA, CTC, DWRBC	Total DA
Total Domestic	0.6	5.6	1.4	7.7	1.7	9.4
GS-1	0.5	4.0	1.2	5.7	1.5	7.2
TC-1	0.0	0.2	0.0	0.2	0.1	0.3
GS-2	8.8	56.4	28.1	93.2	16.9	110.1
TOU-GS-3	12.7	78.5	39.0	130.2	26.1	156.3
Total LSMP	21.9	139.1	68.3	229.4	44.5	273.9
TOU-8-Sec	14.1	69.7	38.6	122.4	22.4	144.8
TOU-8-Pri	10.3	47.4	29.9	87.7	16.2	103.9
TOU-8-Sub	12.0	13.0	38.5	63.5	19.2	82.7
Total Large Power	36.4	130.2	107.0	273.6	57.8	331.4
Total Ag.&Pumping	0.3	2.4	1.6	4.4	2.4	6.8
Total Street Lighting	0.1	1.1	0.4	1.5	0.6	2.1
STANDBY/SEC	0.2	1.2	0.7	2.1	0.4	2.5
STANDBY/PRI	0.9	4.7	2.1	7.8	1.2	8.9
STANDBY/SUB	2.0	2.6	5.3	9.9	2.9	12.8
Total Standby	3.2	8.5	8.1	19.8	4.4	24.2
Total System	**62.7**	**286.9**	**186.9**	**536.5**	**111.4**	**647.8**

In contrast to the total DA revenues in Table RA-5, the total DA revenues shown in the "Total DA" column of Table B-4 reflect the output of SCE's Model, including capping and redistribution of revenues associated with the CARE surcharge.