ATTACHMENT A

List of Appearances

********** ATTACHMENT A: LIST OF APPEARANCES **********
Last Updated on 26-JUN-2009 by: RC4
A0803002 LIST
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(END OF ATTACHMENT A)

ATTACHMENT B

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, And Design Rates	))))	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	))))	Application 07-12-020 (Filed December 21, 2007)

REVENUE ALLOCATION SETTLEMENT AGREEMENT
SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2
A.08-03-002/A.07-12-020

Dated: December 23, 2008

#1592688.v6

Southern California Edison Company
Phase 2 Revenue Allocation Settlement Agreement
A.08-03-002/A.07-012-020

SETTLEMENT OF REVENUE ALLOCATION ISSUES IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON COMPANY'S 2009 GENERAL RATE CASE (PHASE 2 REVENUE ALLOCATION AGREEMENT)

This Phase 2 Revenue Allocation Agreement (Agreement or Settlement Agreement) is entered into by 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 Division of Ratepayer Advocates (DRA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); Federal Executive Agencies (FEA); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF) Indicated Commercial Parties (ICP); California City-County Street Light Association (CAL-SLA); the Solar Alliance; the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA); and the Energy Producers and Users Coalition (EPUC); (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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. CFBF is a voluntary, private, non-profit corporation representing more than 85,000 members and over 80 percent of California's commercial agriculture.

e. 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.

f. 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.

g. Energy Users Forum 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 either investor-owned utility and/or municipal utility service areas, taking service on rate schedules for accounts with demand above 100 kW. EUF represents entities that have accounts taking service on all SCE rate schedules from GS-2 to TOU-8 Subtransmission.

h. 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.

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

j. ICP is an ad hoc group composed of government, health care, and retail entities who receive service on commercial rate schedules. The members of

ICP include the County of Los Angeles, the Los Angeles Unified School District, and Lowe's Home Improvement Warehouses, Inc.

k. CAL-SLA represents cities and counties that take street and area lighting and traffic signal services from SCE and the other two major investor-owned utilities, Pacific Gas & Electric Company and San Diego Gas & Electric Company.

l. BOMA consists of associations of commercial real estate professionals that own, manage, or otherwise service commercial office buildings in SCE's service territory and within California. BOMA members own or manage in excess of 600 million square feet of commercial office space that is occupied by small and medium sized businesses.

m. EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Conoco Phillips Company, Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company – California

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

2. Recitals

a. In Phase 2 of SCE's 2009 General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.) 08-03-002. SCE's A. 07-12-020, filed December 21, 2007, was consolidated with A.08-03-002 on March 26, 2008. SCE updated its initial prepared testimony on June 27, 2008.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners served their initial testimony on October 31, 2008.

e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020, desire to resolve all issues related to allocation of SCE's authorized revenue requirement, and have reached agreement as indicated in Paragraph 5 of this Agreement.

3. <u>Comparison Exhibit</u>

As required by Rule 12.1, because this settlement pertains to a proceeding under the Rate Case Plan, SCE and DRA have provided a comparison exhibit indicating the relative impact of the Agreement compared to SCE's and DRA's respective litigation positions. Those comparisons are provided in Appendix A to this Agreement.

4. <u>Definitions</u>

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

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

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

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 DWR’s costs of power procurement that have been allocated to SCE and the costs of repaying the bonds that were issued to repay the General Fund of California. It consists of both the DWR Power Charge revenue requirement and the DWR Bond Charge revenue requirement.

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

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

h. “Marginal Cost” means the change in total cost due to a small change in the quantity produced or provided.

i. “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.

j. “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.

k. “Rate Case Plan” means D. 89-01-040, as modified by D. 93-07-030 and D.07-07-004 for processing by the Commission of SCE rate cases.

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

m. "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.

n. "Settling Parties" means SCE, DRA, TURN, CFBF, AECA, ICP, EUF, CMTA, CLECA, FEA, CAL-SLA, BOMA, Solar Alliance, and EPUC,.

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

p. "TOU" means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary in relation to the cost of service.

5. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in Paragraph 5 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 11. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. **Marginal Costs**

This Agreement does not reflect approval or acceptance of any of the Parties' marginal cost proposals as the basis for the agreed-upon Phase 2 Revenue Allocation Agreement which is described in Paragraph 5.b with illustrative results provided in Appendix B. Except as otherwise expressly provided in this Agreement, the Settling Parties agree that it is reasonable to use the marginal costs set forth below in Paragraphs 5.a.i, 5.a.ii, and 5.a.iii for the sole purpose of establishing unit marginal costs that are used where applicable to set floors for energy, customer, or demand charges for certain customer classes.

i. **Generation Marginal Energy and Capacity Costs**

Generation marginal energy costs incorporated in this Agreement shall be based on a forecast gas price of $7.00 per million BTUs averaged over 36 months from January 2009 through December 2011. The hourly marginal energy costs derived from this gas price forecast using SCE's methodology set forth in Exhibit SCE-02 (updated) are averaged by TOU periods. Generation marginal capacity cost shall be based on the deferral value of a gas-fired combustion turbine (CT), with the installation cost annualized using SCE's Real Economic Carrying Charge (RECC) methodology, less the estimated value of energy rents obtained by CT energy sales, which yields a generation marginal capacity cost of $114.10 per kW per year. This generation marginal capacity cost is allocated to TOU periods by the relative loss of load expectation measure. When the amount of the general plant loader is subtracted from this generation marginal capacity cost, a net value of $108.00 per kW per year results. Unless modified through subsequent rate design settlement agreements applicable to specific rate groups, this net marginal capacity cost shall also be the basis for the rate credits provided for non-firm service, price response programs, and reliability programs. Generation marginal costs by season and time-of-use periods shall be as follows:

Generation Marginal Cost (2009$)						
		Summer			Winter	
	On-Peak	Mid-Peak	Off-Peak		Mid-Peak	Off-Peak
Energy Cost (¢/kWh) Annual 5.34 ¢/kWh	7.27	6.05	4.60		5.95	4.50
CT Proxy ($/kW-year): Annual $114.10/kW-year	79.98	23.39	1.03		9.24	0.46
Relative Loss of Load Expectation	70.1%	20.5%	0.9%		8.1%	0.4%
Notes: Energy cost is an average over 36 months, with a corresponding natural gas price of $7.00 per MM Btu. The CT proxy is based on a forecast installed cost of $969/kW in 2009$. These costs are forecast at the generator level.						

ii. **Marginal Customer Cost**

For purposes of revenue allocation only, marginal customer costs are determined based on 50:50 ratio of SCE's RECC and DRA's NCO marginal customer cost recommendations and shall be as follows:

Rate Group	2009$/customer-month
Domestic	9.83
GS-1	18.90
TC-1	15.09
GS-2	140.96
TOU-GS-3	331.57
TOU-8- Secondary	337.44
TOU-8- Primary	191.97
TOU-8-Subtransmission	1207.38
PA-1	56.83
PA-2	90.66
AG-TOU	147.62
TOU-PA-5	167.81
Street Lighting	15.75

iii. **Marginal Distribution Capacity Cost**

For purposes of revenue allocation only, marginal distribution costs shall be as follows:

Distribution Marginal Cost (2009$)	
	System Design Demand ($/kW-year)
Non-ISO Subtransmission (66 kV)	29
Distribution (12 kV)	69

b. **Revenue Allocation**

The Settling Parties agree that the revenue allocation results listed in Appendix B of this Agreement ("Phase 2 Revenue Allocation Agreement") are reasonable and should be adopted by the Commission. The Phase 2 Revenue Allocation Agreement reflects all of SCE's adopted revenue requirements, including transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, the DWR Power Charge and DWR Bond Charge revenue requirements as of the date of this Agreement, with forecast revenue requirement changes for Phase 1 of SCE's 2009 GRC, SCE's FERC rate case (ER08-1343/1353), and other proceedings.

i. **Mitigation of Impact of Revenue Allocation Changes**

All of SCE's rate groups are expected to receive revenue requirement increases that will be reflected in rates over the period from December 2008 through June 2009. These revenue changes will have disparate impacts on different rate groups based on the functional System Average Percent Change (SAPC) methodology which applies to these revenue changes in accordance with the settlement agreement adopted in D.06-06-067 in Phase 2 of SCE's 2006 GRC. 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 to each rate group effective October 2009.

ii. **Estimated Adjusted Consolidated Revenue Requirement**

For the purpose of this Agreement, SCE has provided an estimated adjusted consolidated revenue requirement. This estimate was derived by accounting for certain one-time annual reductions in SCE's authorized revenues for 2009. These reductions will no longer be reflected in SCE's authorized revenues by early 2010, and include the following: 1) The suspension of SCE's collection of the CSI revenue requirement in compliance with D.08-12-004; 2) the end of the one-year PBR refund period that was established by D.08-09-038; and 3) the refund of unspent CEC Renewables monies. In addition, SCE assumed that by the end of 2009, the payoff of the DA-CRS undercollection amount will have occurred, thereby resulting in adjustments to certain bundled service and DA revenues in accordance with D.06-07-030. For bundled-service customers, this estimated adjusted consolidated revenue requirement represents a system average percentage change (SAPC) increase of 13.4 percent from December 2008 rate levels. To develop the estimated rates that would be implemented on October 1, 2009 as a result of this Agreement, SCE reduced the estimated adjusted consolidated revenue requirement to incorporate the effect of these one-time revenue reductions in a manner consistent with the functional SAPC revenue allocations agreed to in Paragraph 5.b.v below. SCE also adjusted its generation revenue requirements to account for the CRS loan repayment from "Small" to "Large" bundled service customers triggered by the full recovery of the DA-CRS undercollection amount. Pursuant to D.06-07-030, these loan repayment adjustments were made in the same proportion as the loans were provided.

iii. **Caps on Revenues Allocated to Rate Groups**

As a result of the revenue allocation methods and marginal costs applied to SCE's CPUC-authorized revenue requirements, each rate group receives different outcomes relative to the system average percentage change. The Settling Parties agree that no rate group shall receive an increase of more than 2.75 percent above the system average percentage change based on SCE's adjusted consolidated revenue requirement. The undercollection of SCE's authorized revenues resulting from this capping shall be allocated based on percentage of generation marginal cost revenues to the rate groups whose increases are not otherwise capped.

iv. **Additional Capping of Street Light Rate Group Nonallocated Revenues**

The Settling Parties agree that nonallocated revenues assigned to the Street Light rate group should be limited so that for the period from October 1, 2009 through September 30, 2012, *i.e.*, Phase 2 of SCE's 2012 GRC, the facilities-related charges that are established in accordance with the "Southern California Edison Company 2009 GRC, Phase 2 Street Light Rate Group Settlement Agreement" do not increase by more than 4.8 percent per year from the December 2008 level of such charges. Any revenue deficiency associated with the establishment of facilities-related charges for Street Light rate schedules in accordance with this limitation shall be recovered from all rate groups, with the deficiency allocated on the basis of distribution revenues.

v. **Allocation of CPUC and FERC-Authorized Revenue Requirements**

The Settling Parties agree that all of SCE's CPUC- and FERC-authorized revenue requirements shall be allocated in proportion to the components as specified in Paragraph 5.b.vii below, to produce the allocation of revenues and corresponding rate levels for each rate group proportional to those shown in Appendix B, and shall be adjusted to reflect SCE's actual total system revenue requirement when implemented. Revenue changes and rates for DA customers based on the adjusted consolidated revenue requirement are also shown in Appendix B.

vi. **Adjustments To Revenue Requirements**

The levels of revenues and rates reflected in Appendix B are illustrative and are based on the adjusted consolidated revenue requirement of $12,234 million described in Section 5.b.ii, above. To the extent the revenue requirements assumed to result from these CPUC or FERC proceedings change from this assumption, or the Commission adopts other revenue changes, the Settling Parties agree that such changes shall be reflected in the settlement revenues and average rates listed in Appendix B in proportion to the change in revenue requirement from the revenue requirements reflected in Appendix B of this Settlement subject to the agreed upon revenue caps. The Parties agree that SCE shall provide such changes to the assigned ALJ in this proceeding and to the Commission if such changes occur prior to the issuance of a Commission decision adopting this Agreement.

vii. **Unbundled Revenue Requirements**

Without effecting any change to the agreed-upon Phase 2 Revenue Allocation Agreement in Appendix B, to produce unbundled rates for rate design purposes in this proceeding and to provide a basis for implementing other revenue requirement changes occurring after this proceeding and before SCE's next revenue allocation proceeding, SCE's authorized revenue requirements shall be allocated to rate groups as follows:

a. **FERC-Jurisdictional, Transmission Revenue Requirement**

SCE's FERC-approved rates for transmission and SCE's forecast billing determinants shall be used to determine the transmission revenue requirement recovered from each rate group. Individual rate components adopted by FERC shall be added to the CPUC-jurisdictional rates, resulting in total delivery service rates.

b. **Distribution-Related Revenue Requirement**

1. SCE's CPUC-approved distribution revenue requirement shall be allocated to rate groups based on the marginal distribution costs defined in Section 5.a.iii of this Agreement, and based on the marginal customer costs listed in Paragraph 5.a.ii of this Agreement, with marginal customer cost revenue responsibility calculated based on these values. Marginal distribution cost revenues shall be calculated by applying the

marginal distribution capacity costs to the diversified demands of various rate groups at the appropriate voltage levels. Because distribution rates are developed for all retail customers, marginal customer and distribution cost revenues are based on combined direct-access (DA) and bundled-service demand and number of customers.

2. Interruptible rate program credits (*e.g.* Base Interruptible Program, Summer Discount Plan, and Agricultural/Pumping-Interruptible) shall be based upon SCE's forecast of program participation and credit levels. These costs shall be allocated to rate groups for recovery in distribution rates from bundled-service and DA customers based on the marginal generation cost allocator, which imputes marginal generation costs to DA customers in each rate group as if they were bundled-service customers.
3. Non-allocated revenues consist primarily of Street Lighting facilities costs and power factor adjustment revenues as derived by SCE. These revenues shall be assigned directly to the rate groups responsible for incurring the costs except that for purposes of this Agreement, non-allocated revenues assigned to the Street and Area Lighting rate group shall be capped as reflected in Paragraph 5.b.iv of this Agreement, with the residual revenue deficiency resulting from this limit allocated among all rate groups on the same basis as distribution revenues.
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 a cents per kWh basis.

c. **Generation Revenue Requirement**

1. The DWR Revenue Requirement, net of contribution by DA customers, shall be combined with SCE's other generation-related revenue requirements and shall be allocated to rate groups for recovery from bundled-service customers based on marginal generation cost revenues.
2. For the purpose of this Agreement, SCE's generation revenue requirement, net of contributions from DA customers, that is allocated to each rate group shall be determined residually, *i.e.*, by subtracting the functional allocation of all other revenue requirements to each rate group from the total revenue requirement allocated to that rate group that is shown in the Phase 2 Revenue Allocation Agreement in Appendix B.
3. Generation-related administrative and general (A&G) costs are assumed to be reflected in SCE's generation revenue requirement and shall be recovered in SCE's generation rate component from bundled-service customers.

d. **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.

e. **DA Cost Responsibility Surcharge**

For the purpose of this Agreement, the DA CRS undercollection revenue responsibility is assumed to be fully recovered. This assumption also triggers the "small"/"large" loan repayment adopted in D.03-07-029 and authorized in

D.06-07-030. The full level of the 2009 DA CRS for DA customers is estimated to be 1.584 cents per kWh. Thus, the 2.7 cents per kWh cap no longer applies after the assumed full recovery of the DA CRS undercollection.

f. **Nuclear Decommissioning Revenue Requirement**

In accordance with D. 00-06-034, SCE's CPUC-jurisdictional nuclear decommissioning revenue requirement shall be allocated on an equal cents per kWh basis, reflecting total retail sales.

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

SCE's CPUC-jurisdictional Public Purpose Programs revenue requirement shall be allocated using the current system average percentage (SAP) method and shall be based upon all retail sales, including DA sales (with generation imputed). 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. SCE's authorized revenue requirement for the California Solar Initiative (CSI) shall be allocated on the same SAP basis and shall be recovered on a cent per kWh basis in the PPP component of SCE's delivery charges.

h. **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 and Area Lighting 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 and Area Lighting rate group. The CARE surcharge is reflected in the PPP charge.

i. **Edison SmartConnect Cost Allocation**

Edison SmartConnect costs shall be allocated as distribution costs.

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

The 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 2012 GRC proceeding is implemented shall be allocated according to the functional character of the revenue requirement change on an SAPC basis using the allocators set forth at page A-2 of Appendix A of Exhibit SCE-3 (updated), Summary of 2009 Revenue Allocators. For example, revenue changes resulting from the ERRA proceeding shall be allocated on an SAPC basis, *i.e.*, a revised SCE generation revenue requirement would be combined with the DWR Power Charge revenue requirement to calculate an SAPC factor for the sum of SCE generation and DWR generation revenue requirements. The SAPC factor would then be applied to the combined generation rate, and then the adopted DWR Power Charge would be subtracted from the combined generation rate to calculate the SCE generation rate. To the extent necessary, based on "Southern California Edison Company 2009 GRC, Phase 2 Street Light Rate Group Settlement Agreement," streetlight facilities charges are capped until Phase 2 of SCE's 2012 GRC is implemented, the revenue deficiency shall be recovered from all rate groups as provided in Paragraph 5.b.iv.

6. Implementation of Agreement

It is the intent of the Parties and their request that the Commission adopt this Agreement on an expedited basis. Furthermore, it is the intent of the 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 October 1, 2009.

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 Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

8. Signature Date

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

9. Regulatory Approval

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) 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 Parties. The Parties have reached this Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The 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 Communications

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the 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 Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce Reed

Title: Senior Attorney Date: 1/7/2009

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling

Title: Director Date: 1/7/2009

THE UTILITY REFORM NETWORK

By: /s/ Hayley Goodson

Title: Staff Attorney Date: 1/7/2009

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ron Liebert

Title: Associate Counsel Date: 12/24/2008

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

By: /s/ Dan Geis

Title: Assistant Executive Director Date: 1/8/2009

FEDERAL EXECUTIVE AGENCIES

By: /s/ Norman Furuta

Title: Associate Counsel Date: 1/8/2009

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ Keith R. McCrea

Title: Attorney Date: 1/9/2009

ENERGY USERS FORUM

By: /s/ Carolyn Kehrein

Title: Consultant Date: 1/7/2009

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ William Booth

Title: Attorney Date: 1/8/2009

INDICATED COMMERCIAL PARTIES

By: /s/ Randall W. Keen

Title: Manatt, Phelps & Phillips, LLP Attorneys for Indicated Commercial Parties Date: 1/8/2009

BOMA

By: /s/ B.F. Roberts

Title: President, Economic Sciences Corp. Date: 1/8/2009

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ Reed V. Schmidt

Title: Energy Consultant Date: 1/8/2009

SOLAR ALLIANCE

By: /s/ R. Thomas Beach

Title: Consultant Date: 1/9/2009

ENERGY PRODUCERS AND USERS COALITION

By: /s/ Nora Sheriff

Title: Counsel Date: 1/8/2009

Appendix A

Comparison of SCE and DRA Revenue Allocation Proposals

Comparison of SCE, DRA And Settlement Revenue Allocation Proposals
Bundled Service Rate Comparison
Illustrative Rates (¢/kWh)

	December 2008 Average Rates	SCE Errata Proposal (Uncapped)		DRA Proposal (Capped)		Proposed Settlement	
		Proposed Rate	Percent Change	Proposed Rate	Percent Change	Proposed Rate	Percent Change
Total Domestic	14.91	17.37	16.5%	16.71	12.0%	17.32	16.1%
GS-1	16.93	17.82	5.3%	18.07	6.7%	18.72	10.6%
TC-1	15.14	20.05	32.4%	16.96	12.0%	17.58	16.1%
GS-2	14.51	15.51	6.9%	16.00	10.3%	16.85	16.1%
TOU-GS-2	13.22	13.41	1.4%	14.19	7.4%	14.35	8.6%
Total LSMP	14.56	15.34	5.3%	15.86	8.9%	16.48	13.2%
TOU-8-Sec	12.37	12.65	2.3%	13.33	7.8%	13.62	10.1%
TOU-8-Pri	11.70	11.62	-0.7%	12.34	5.4%	12.51	6.8%
TOU-8-Sub	7.63	8.85	16.0%	8.55	12.0%	8.86	16.1%
Total Large Power	10.79	11.25	4.3%	11.65	8.0%	11.87	10.1%
PA-1	18.60	20.01	7.6%	18.74	0.7%	19.88	6.9%
PA-2	13.01	14.45	11.1%	14.51	11.5%	14.80	13.8%
AG-TOU	9.71	12.43	28.0%	10.88	12.0%	11.27	16.1%
TOU-PA-5	9.51	12.59	32.5%	10.65	12.0%	11.04	16.1%
Total Ag & Pumping	11.19	13.72	22.5%	12.26	9.5%	12.68	13.3%
Total Street Lighting	18.63	21.31	14.4%	20.87	12.0%	20.66	10.9%
Total System	13.73	15.13	10.2%	15.11	10.0%	15.57	13.4%

Note: The settlement revenue allocation depicted in this comparison incorporates more recent revenue requirement estimates and therefore cannot be directly compared to the SCE and DRA proposals. This comparison shows the initial litigation positions of SCE and DRA along with the proposed settlement position. DRA proposed rates are derived from DRA's testimony.

Appendix B

Phase 2 Revenue Allocation Agreement

Phase 2 Revenue Allocation Agreement

Bundled-Service Rate Groups

Illustrative Rates

	Bundled Service Average Rates (¢/kWh)					Relative Percentage Changes						Percent of System Average Rate	
	Dec. 2008	Jan. 2009	June 2009	Oct. 1, 2009	**Proposed Settlement**								
	A	B	C	D	**E**	B/A	C/A	D/A	E/A	D/C	E/D	A	E
Total Domestic	14.9	14.8	16.1	16.4	**17.3**	-0.8%	8.1%	9.8%	16.1%	1.6%	5.7%	109%	111%
GS-1	16.9	16.8	18.1	17.7	**18.7**	-1.1%	6.7%	4.7%	10.6%	-1.8%	5.6%	123%	120%
TC-1	15.1	14.5	15.8	16.5	**17.6**	-4.2%	4.1%	9.1%	16.1%	4.9%	6.4%	110%	113%
GS-2	14.5	14.3	15.7	15.9	**16.9**	-1.3%	8.4%	9.9%	16.1%	1.4%	5.7%	106%	108%
TOU-GS-3	13.2	12.8	14.4	13.5	**14.3**	-2.9%	8.6%	1.9%	8.6%	-6.2%	6.6%	96%	92%
Total LSMP	14.6	14.4	15.8	15.6	**16.5**	-1.4%	8.2%	6.9%	13.2%	-1.2%	5.9%	106%	106%
TOU-8-Sec	12.4	12.2	13.0	12.8	**13.6**	-1.3%	5.3%	3.6%	10.1%	-1.6%	6.3%	90%	88%
TOU-8-Pri	11.7	11.5	12.3	11.7	**12.5**	-2.1%	5.3%	0.1%	6.8%	-4.9%	6.7%	85%	80%
TOU-8-Sub	7.6	7.5	7.9	8.3	**8.9**	-1.1%	3.0%	8.2%	16.1%	5.0%	7.3%	56%	57%
Total Large Power	10.8	10.8	11.3	11.1	**11.9**	0.2%	4.5%	3.2%	10.1%	-1.2%	6.6%	79%	76%
PA-1	18.6	18.4	19.6	18.8	**19.9**	-0.9%	5.2%	1.0%	6.9%	-4.0%	5.8%	135%	128%
PA-2	13.0	12.8	13.8	14.0	**14.8**	-1.4%	5.8%	7.2%	13.8%	1.4%	6.1%	95%	95%
AG-TOU	9.7	9.1	10.3	10.5	**11.3**	-6.0%	6.0%	8.3%	16.1%	2.1%	7.3%	71%	72%
TOU-PA-5	9.5	9.4	9.7	10.3	**11.0**	-1.3%	2.2%	8.7%	16.1%	6.3%	6.8%	69%	71%
Total Ag.&Pumping	11.2	10.9	11.7	11.9	**12.7**	-2.3%	4.3%	6.1%	13.3%	1.7%	6.7%	82%	81%
Total Street Lighting	18.6	18.5	19.7	19.6	**20.7**	-0.7%	5.9%	5.3%	10.9%	-0.5%	5.3%	136%	133%
Total System	13.7	13.6	14.7	14.7	**15.6**	-1.0%	6.9%	7.0%	13.4%	0.1%	6.0%	100%	100%

Column A: Actual rates effective December 2008.

Column B: Actual rates effective January 1, 2009 based on revenue requirement changes, including DWR Power Charge, DWR Bond Charge, and Transmission balancing accounts, implemented on a functional SAPC basis.

Column C: Forecast rates based on actual rates in Column B, plus assumed revenue requirement increases allocated on a functional SAPC basis on or before June 1, 2009 for the following applications: Phase 1 SCE 2009 GRC (alternate proposed decision), December 2008 ERRA Trigger, SCE's FERC GRC, 2009-2011 Energy Efficiency and Demand Response Programs. Forecast rates also reflect various one-time revenue adjustments that occur in 2009, including the suspension of CSI revenue collection, PBR OII refund, PG&E DWR Accelerated Payment, and CEC renewable energy refund.

Column D: Forecast rates effective October 1, 2009 based on same total revenue requirement assumed for Column C, adjusted (Paragraph 5.b.ii) to achieve the same effective allocation of revenues to each rate group as shown in Column E.

Column E: Forecast rates at end of year 2009 based on estimated adjusted revenue requirement (Paragraph 5.b.ii), excluding one-time charges or refunds made in 2009 (suspension of CSI revenue collection, PBR OII refund, CEC renewable energy refund, ERRA trigger revenues, and the repayment of the DA-CRS undercollection) and the results of applying the settlement values for marginal costs (Paragraph 5.a.i-iii), functional SAPC revenue allocations (Paragraphs 5.b.v, 5.b.vii) with a 2.75 % cap on revenues allocated to any one rate group (Paragraph 5.b.iii) and a cap on increases to Street Light facilities charges (Paragraph 5.b.iv). Does not reflect revenue changes for the 2010 ERRA forecast or for 2010 attrition year (2009 GRC).

Phase 2 Revenue Allocation Agreement

Direct Access Rate Groups

Illustrative Settlement Rates

	Rates Effective December 2008 ($/kWh)	Settlement Proposal Rates (¢/kWh)	Settlement Percent Change
Residential	0.08769	0.08701	-0.8%
Lighting, Small and Medium Power			
GS-1	0.08226	0.09274	12.7%
TC-1	0.08104	0.09547	17.8%
GS-2	0.06239	0.06118	-1.9%
TOU-GS-3	0.06426	0.06082	-5.4%
Group Total	0.06372	0.06160	-3.3%
Large Power			
TOU-8-SEC	0.06009	0.05379	-10.5%
TOU-8-PRI	0.05601	0.04861	-13.2%
TOU-8-SUB	0.03788	0.03037	-19.8%
Group Total	0.04878	0.04189	-14.1%
Agricultural & Pumping			
PA-1	0.06040	0.06557	8.6%
PA-2	0.06015	0.05056	-15.9%
TOU-AG	0.04617	0.04120	-10.8%
TOU-PA-5	0.06552	0.05391	-17.7%
Group Total	0.04985	0.04408	-11.6%
Street & Area Lighting	0.05923	0.05636	-4.8%
System Total	0.05278	0.04817	-8.7%

Phase 2 Revenue Allocation Agreement

Proposed Bundled Service Revenues

Adjusted Consolidated Revenue Requirement ($MM)

(Illustrative)

	Trans	Dist.	Other	Total Delivery	URG Gen.	DWR Power	Total Gen.	Total Bundled
Total Residential	230.9	1,673.4	350.3	2,254.6	2,085.5	679.0	2,764.6	5,019.2
GS-1	42.7	292.9	68.1	403.7	393.7	114.1	507.8	911.5
TC-1	0.3	4.7	0.7	5.8	2.8	1.3	4.1	9.9
GS-2	111.4	722.9	184.1	1,018.4	1,057.5	335.3	1,392.8	2,411.3
TOU-GS-3	58.6	303.5	93.3	455.4	458.3	178.3	636.6	1,092.0
Total LSMP	213.0	1,324.0	346.3	1,883.3	1,912.4	629.1	2,541.4	4,424.7
TOU-8-Sec	51.8	230.0	94.0	375.8	531.8	188.6	720.3	1,096.2
TOU-8-Pri	29.3	120.0	58.2	207.5	312.5	119.9	432.4	640.0
TOU-8-Sub	33.8	38.6	53.3	125.6	260.2	123.9	384.1	509.7
Total Large Power	114.9	388.6	205.4	709.0	1,104.6	432.4	1,536.9	2,245.9
PA-1	2.7	30.2	5.8	38.7	30.5	9.2	39.8	78.4
PA-2	1.9	14.0	4.3	20.2	23.8	8.3	32.1	52.3
AG-TOU	5.8	47.6	15.7	69.1	64.8	35.1	99.9	169.0
TOU-PA-5	5.1	22.7	9.3	37.1	41.7	21.2	63.0	100.0
Total Ag.&Pump.	15.5	114.5	35.1	165.0	160.9	73.9	234.7	399.7
Total Street Lights	2.5	90.0	10.3	102.8	25.3	16.4	41.7	144.5
SYSTEM	576.8	3,590.5	947.4	5,114.7	5,288.6	1,830.7	7,119.3	12,234.0

(END OF ATTACHMENT B)

ATTACHMENT C

Residential and Small Commercial Rate Design 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, And Design Rates	))))	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	))))	Application 07-12-020 (Filed December 21, 2007)

2009 GRC PHASE 2 RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

Dated: **January 20, 2009**

2009 GRC Phase 2 Residential and Small Commercial Rate Design Settlement Agreement

2009 GRC PHASE 2 RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Residential and Small Commercial Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by 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 Division of Ratepayer Advocates (DRA); the Solar Alliance, and the Western Manufactured Housing Community Association (WMA) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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

e. WMA is a not-for-profit trade association that represents the owners of both submetered and directly-served manufactured housing communities in California.

2. Recitals

a. In Phase 2 of SCE's 2009 General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners served their initial testimony on October 31, 2008.

e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Residential and Small Commercial Rate Groups as indicated in Paragraph 4 of this Agreement.

3. Definitions

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "AB1X" refers to the special legislation enacted in 2001 which capped residential rates for usage up to 130% of the then-authorized baseline allowances.

b. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

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

d. "CARE" means the California Alternate Rates for Energy program which provides customers meeting a certain household income criteria a discount from SCE's otherwise applicable residential rates.

e. "Customer Charge" means the dollar per month charges applicable to certain Small Commercial Rate Group rate schedules.

f. "CSI" means the California Solar Initiative, and the revenue requirement associated with the CSI that SCE has been authorized to recover from SCE ratepayers.

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

h. "DWR Revenue Requirement" means the revenues collected by SCE on behalf of the DWR to recover the DWR's costs of power procurement that have been allocated to SCE and the costs of repaying the bonds that were issued to repay the General Fund of California. It consists of both the DWR Power Charge revenue requirement and the DWR Bond Charge revenue requirement.

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

j. “PPP” means Public Purpose Programs and the revenue requirement associated with Public Purpose Programs such as the revenue requirement that provides the discount to CARE customers.

k. “Residential Rate Group” means the following rate schedules: Schedule D, Schedule D-APS, Schedule D-APS-E, Schedule D-CARE, Schedule D-FERA, Schedule DM, Schedule DMS-1, Schedule DMS-2, Schedule DMS-3, Schedule MB-E, Schedule TOU-D-T, Schedule TOU-D-1, Schedule TOU-D-2, Schedule TOU-EV, TOU-EV-1, and Schedule TOU-TEV.

l. “SAP” means system average percentage.

m. “Settling Parties” means SCE, DRA, TURN, Solar Alliance, and WMA.

n. “Small Commercial Rate Group” means the following rate schedules: Schedule GS-1, Schedule TOU-GS-1, and Schedule TOU-EV-3.

o. “TOU” means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary in relation to the cost of service.

4. <u>Agreement</u>

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 or an acceptance by any Party of any fact, principle, or position contained herein and this Agreement is subject to the limitations described in Paragraph 10 with respect to the express limitation on precedent. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. **Illustrative Rates**

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix A to this Agreement are reasonable and should be adopted by the Commission. These rates are based on SCE's estimated adjusted consolidated revenue requirement and shall be adjusted consistent with the terms of this Agreement and the Phase 2 Revenue Allocation Settlement Agreement[1] to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

b. **Pricing Agreement**

i. **Tiered Rate Structure**

Energy charges for SCE's Schedule D, and other comparably-structured Residential Rate Group schedules shall reflect five tiers of consumption, *i.e.*, the baseline allocation (as applied in the existing manner to SCE's baseline zones), which is Tier 1; 101% to 130% of the baseline allocation, which is Tier 2; 131% to 200% of the baseline allocation, which is Tier 3; 201% to 300% of the baseline allocation, which is Tier 4; and 301% or more of the baseline allocation, which is Tier 5.

ii. **Basic Charge and Energy Rates For Tiers 1 and 2**

The energy rates for usage up to 130% of the baseline allocation (Tier 1 and Tier 2) shall not be increased above the levels effective on February 1, 2001 except to the extent recovery of CSI revenues were authorized for recovery in Tier 1 and Tier 2 energy rates by Resolution E-4167. However, CSI revenues shall be allocated on the same basis as other PPP revenues on an SAP basis and recovered on a cent per kWh basis as is the PPP component of SCE's delivery charges instead of the allocation method adopted in Resolution E-4167. There shall be no increase made to the Basic Charges on residential rate schedules that were effective as of December 2008. The Basic Charge for all Residential Rate Group TOU options shall be set equal to the single-family Basic Charge effective as of December 2008.

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[1] The Phase 2 Revenue Allocation Settlement Agreement was filed on January 9, 2009.

iii. **Energy Rates For Tiers 3 – 5**

For Schedule D, revenue changes allocated to residential customers shall be reflected in the rates established for Tiers 3, 4, and 5. SCE shall establish rates so that there is a differential of two and one-half cents per kWh between the rates for Tier 3 and Tier 4, and between the rates for Tier 4 and Tier 5. However, if legislation modifying the residential rate protective provisions of AB1X is enacted, which allows at least a three percent annual increase in Schedule D Tier 1 and Tier 2 rates, SCE shall establish rates at the next regularly-scheduled rate change so that there is a three and one-half cent per kWh differential between the rates for Tier 3 and Tier 4, and between the rates for Tier 4 and Tier 5.

iv. **Baseline Zone Modification**

In accordance with SCE's Exhibit SCE-4 (updated), dated June 27, 2008, SCE's six baseline zones shall be revised to align with the nine climate zones established by the California Energy Commission (CEC) to provide a more accurate basis for establishing baseline allocations. Customers currently residing in SCE's existing baseline zone 15 shall retain their currently designated baseline zone.

v. **Baseline Allocation**

SCE shall update its baseline allowances to reflect current usage levels and reduce baseline allocation percentages for each baseline zone to 50 percent of the average aggregate customer usage. However, if legislation modifying the residential rate protective provisions of AB1X is enacted, which allows at least a three percent annual increase in Schedule D Tier 1 and Tier 2 rates, SCE shall use then-current usage levels and establish rates at the next regularly-scheduled rate change with the baseline allocation percentages for each baseline zone set at 55 percent of the average aggregate customer usage. SCE has excluded the impact of seasonal residents from the determination of baseline allocations for zones 15 and 16. The baseline kilowatt-hour allowance for each revised baseline zone based on the CEC climate zones shall not be less than the allowance in effect in the baseline zones that existed on February 1, 2001.

vi. **D-CARE Structure**

Energy charges for Schedule D-CARE shall reflect three different energy charges, which increase from Tier 1 to Tier 2 and to Tier 3. The Schedule D-CARE Tier 3 rate shall be established at a level that provides a discount of 20 percent from the Schedule D Tier 3 rate level subject to a ceiling of 20 cents per kilowatt hour (with any additional CARE surcharge revenue deficiency resulting from the rate ceiling recovered solely from the Residential Rate Group) after excluding the CARE surcharge component of the Public Purpose Program charge, the DWR Bond Charge, and any applicable CSI rate component that otherwise applies to the Tier 3 rate for Schedule D.

vii. **D-FERA Structure**

Energy charges for Schedule D-FERA shall reflect five tiers; however, the energy rate for Tier 3 shall be set at the Tier 2 energy rate level.

viii. **Demand Response Rates (Summer Discount Plan (SDP), Peak Time Rebate (PTR), Programmable Communicating Thermostat (PCT), and Critical Peak Pricing (CPP))**

SCE's demand response proposals and eligibility criteria set forth in Exhibit SCE-4 (updated) for the SDP, PTR, PCT, and CPP shall be adopted with the exception that the technology-enabled incentive for the PTR and PCT programs shall be $1.25/kWh for the three-year cycle of SCE's 2009 GRC. SCE will make good faith efforts to align the trigger mechanism for the SDP (Schedules D-APS, D-APS-E, and GS-APS) with the trigger mechanism for the Base Interruptible Program (BIP) for nonresidential customers. The basis for the SDP and CPP rate designs shall be consistent with SCE's proposed capacity valuation method. To the extent that "free-rider ship" credits are quantified for the PTR program, the revenue credits associated with "free rider ship" shall be recovered from the Residential Rate Group. SCE intends to conduct a study to estimate the level of free-rider ship credits for the PTR program, and to make a future request to recover this revenue deficiency from residential customers given that the revenue deficiency would be otherwise recovered from all ratepayers through the Energy Resource Recovery Account (ERRA) balancing account.

ix. **TOU-D Schedules**

Schedules TOU-D-1 and TOU-D-2 will be closed to new customers but existing customers shall be grandfathered on these rate schedules for the three-year term of SCE's 2009 GRC cycle. Schedule TOU-D-T shall be established as a 2-tiered TOU rate structure with the same TOU periods as the current TOU schedules. The lower rate tier of this new TOU structure will be designed to be revenue neutral to the otherwise applicable tariff's Tier 1 and Tier 2 rates, *e.g.*, Schedule D or Schedule D-CARE, while the higher tier will be designed to be revenue neutral to the otherwise applicable tariff's Tier 3 through Tier 5 rates. This structure will apply to Schedules TOU-D-T and TOU-TEV. No incremental TOU meter charges will apply to these four rate schedules.

x. **Schedule TOU-TEV**

Schedule TOU-EV shall be offered as a new rate option for customers who prefer single meter service for a primary residence with an electric vehicle load. Schedule TOU-TEV shall have on-peak, off-peak and super-off peak TOU periods. The on-peak period shall be between 10:00 a.m. and 6:00 p.m. all year except holidays. The super off-peak period shall be between midnight and 6:00 a.m. all year, every day. The off-peak period will comprise the balance of the hours. Energy pricing for Schedule TOU-TEV shall provide discounted super off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges.

xi. **Schedule TOU-EV-1**

Schedule TOU-EV-1 shall be modified to provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges. TOU meter charges will be removed from this schedule. In order to make this revision available earlier than October 1, 2009, SCE shall implement the modified Schedule TOU-EV-1 as soon as practicable after Commission approval of this Settlement Agreement.

xii. **Submetering Discount**

The discount provided to customers who provide submetered electric service and who are served on Schedule DMS-2 shall be $0.148 per space per day. This value reflects a cost-of-service discount of $0.34 decreased by a diversity adjustment of $0.17 per space per day, and decreased by a Basic Charge adjustment of $0.022 per space per day. The diversity adjustments for Schedules DM and DMS-1 shall also be $0.17 per space per day. In accordance with prior practice, the discount provided to customers served on Schedule DMS-1, shall be set at a level that maintains the current ratio (28.6%) between the submetering discounts for Schedules DMS-1 and DMS-2.

WMA has recommended changes in how the baseline allowances are applied during the Schedule DMS-2 bill calculation. SCE will identify the billing system changes and associated costs required to implement WMA's recommendations. If feasible, SCE will implement WMA's recommended changes to the DMS-2 billing calculation, and will thereafter decrease the diversity adjustment by two cents to $0.15 per space per day. The Settling Parties agree that the billing calculation change and the two cent decrease in the diversity adjustment will roughly offset each other, such that total bills for Schedule DMS-2 customers will not change.

xiii. **Conservation Incentive Adjustment**

As SCE proposed in Exhibit SCE-4 (updated), in accordance with the Conservation Incentive Adjustment proposal, SCE shall restructure its residential rates to reflect the rate differentials between tiers in the delivery component of those rates instead of the generation component.

xiv. **Medical Baseline**

Medical baseline rates shall be designed as described in Exhibit SCE-4 (Updated).

xv. **Schedules DE and DS**

Schedules DE (employee/retiree discount) and DS (optional seasonal pricing) shall be retained with the existing eligibility provisions and as currently structured.

c. **Reporting of Residential Arrearages and Shutoffs**

For the period beginning January 2009 and ending December 2011, SCE shall provide to the Director of the Commission's Energy Division monthly and annual reports listed and at the times specified in Appendix B.

d. **GS-1 Rate Group**

i. Customer Charges and Seasonal Rates

Effective with the implementation of this Settlement Agreement, SCE shall not increase the Schedule GS-1 Customer Charge and the Schedule TOU-GS-1 Customer Charge from their then-current levels on October 1, 2009. Changes to the Schedule GS-1 and Schedule TOU-GS-1 Customer Charges after October 1, 2009 shall be based on Functional SAPC Allocation of distribution revenue changes. SCE will implement its proposed seasonally-differentiated energy charge for Schedule GS-1 reflecting the seasonal differences in marginal energy and capacity costs.

ii. Schedule TOU-GS-1

SCE's proposals for Schedule TOU-GS-1 contained in Exhibit SCE-04 (Updated), dated June 27, 2008, shall be adopted, except for SCE's proposed increase to the Customer Charge. The proposed Schedule TOU-GS-1 meter charge shall be eliminated.

iii. Schedule TOU-EV-3

Schedule TOU-EV-3 off-peak energy charges will provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges as defined by D.07-11-052. On-peak energy charges will be set consistent with TOU-GS-1 on-peak energy charges but will reflect the different time-period definitions offered for the charging of commercial electric vehicles and incremental revenue recovery associated with the provided off-peak discount. Effective with the implementation of this Settlement

Agreement, SCE shall not increase the Schedule TOU-EV-3 Customer Charge from its then-current level on October 1, 2009. Changes to the Schedule TOU-EV-3 Customer Charge after October 1, 2009 shall be based on Functional SAPC Allocation of distribution revenues. TOU meter charges shall be removed from Schedule TOU-EV-3.

5. Implementation of Agreement

It is the intent of the Parties and their request that the Commission adopt this Agreement on an expedited basis. Furthermore, it is the intent of the 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.

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 Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

7. Signature Date

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

8. Regulatory Approval

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

9. Compromise Of Disputed Claims

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

10. 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.

11. Previous Communications

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the 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.

12. 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.

13. Effect Of Subject Headings

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

14. 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.

15. 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 Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: January 23, 2009

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling

Title: Director Date: January 23, 2009

THE UTILITY REFORM NETWORK

By: /s/ Hayley Goodson

Title: Staff Attorney Date: January 21, 2009

Solar Alliance

By: /s/ Tom Beach

Title: Director of Programs Date: January 23, 2009

WESTERN MANUFACTURED HOUSING COMMUNITY ASSOCIATION

By: /s/ Edward G. Poole

Title: Counsel Date: January 21, 2009

Appendix A
Illustrative Rates for Residential and Small Commercial Rate Schedules

Phase 2 Residential and Small Commercial Rate Design Settlement Agrement

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates Based on Estimated Adjusted Revenue			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
D							
Energy Charge- $/kWh							
Baseline - Summer	0.07217	0.04861	0.12078	0.02405	0.09571	0.11976	-0.85%
- Winter	0.07217	0.04861	0.12078	0.02405	0.09571	0.11976	-0.85%
101% - 130% of Baseline - Summer	0.07217	0.06794	0.14011	0.04338	0.09571	0.13909	-0.73%
- Winter	0.07217	0.06794	0.14011	0.04338	0.09571	0.13909	-0.73%
131% - 200% of Baseline - Summer	0.07217	0.13559	0.20776	0.18230	0.09571	0.27801	33.81%
- Winter	0.07217	0.13559	0.20776	0.18230	0.09571	0.27801	33.81%
200% - 300% of Baseline - Summer	0.07217	0.17059	0.24276	0.21730	0.09571	0.31301	28.94%
- Winter	0.07217	0.17059	0.24276	0.21730	0.09571	0.31301	28.94%
Over 300% of Baseline	0.07217	0.20559	0.27776	0.25230	0.09571	0.34801	25.29%
- Winter	0.07217	0.20559	0.27776	0.25230	0.09571	0.34801	25.29%
Basic Charge - $/day							
Single-Family Residence	0.029	0.000	0.029	0.029		0.029	0.00%
Multi-Family Residence	0.022	0.000	0.022	0.022		0.022	0.00%
Minimum Charge - $/day							
Single Family Residence	0.059	0.000	0.059	0.059		0.059	0.00%
Multi-Family Residence	0.044	0.000	0.044	0.044		0.044	0.00%
D-CARE							
Energy Charge - $/kWh							
Baseline - Summer	0.03672	0.04861	0.08533	(0.01038)	0.09571	0.08533	0.00%
- Winter	0.03672	0.04861	0.08533	(0.01038)	0.09571	0.08533	0.00%
101% - 130% of Baseline - Summer	0.03874	0.06794	0.10668	0.01097	0.09571	0.10668	0.00%
- Winter	0.03874	0.06794	0.10668	0.01097	0.09571	0.10668	0.00%
131% - 200% of Baseline - Summer	0.02301	0.13559	0.15860	0.10429	0.09571	0.20000	26.10%
- Winter	0.02301	0.13559	0.15860	0.10429	0.09571	0.20000	26.10%
200% - 300% of Baseline - Summer	(0.01199)	0.17059	0.15860	0.10429	0.09571	0.20000	26.10%
- Winter	(0.01199)	0.17059	0.15860	0.10429	0.09571	0.20000	26.10%
Over 300% of Baseline	(0.04699)	0.20559	0.15860	0.10429	0.09571	0.20000	26.10%
- Winter	(0.04699)	0.20559	0.15860	0.10429	0.09571	0.20000	26.10%
Basic Charge - $/day							
Single-Family Residence	0.023	0.000	0.023	0.023		0.023	0.00%
Multi-Family Residence	0.017	0.000	0.017	0.017		0.017	0.00%
Minimum Charge - $/day							
Single Family Residence	0.047	0.000	0.047	0.047		0.047	0.00%
Multi-Family Residence	0.034	0.000	0.034	0.034		0.034	0.00%
D-APS							
Air Conditioning Cycling							
Credit - $/ton/summer season day							
50% Cycling	(0.05)	0.00	(0.05)	(0.04)		(0.04)	30.00%
67% Cycling	(0.10)	0.00	(0.10)	(0.07)		(0.07)	27.00%
100% Cycling	(0.18)	0.00	(0.18)	(0.36)		(0.36)	-98.89%
D-APS-E							
Air Conditioning Cycling							
Credit - $/ton/summer season day							
50% Cycling	(0.10)	0.00	(0.10)	(0.04)		(0.04)	60.00%
67% Cycling	(0.20)	0.00	(0.20)	(0.08)		(0.08)	59.00%
100% Cycling	(0.36)	0.00	(0.36)	(0.41)		(0.41)	-13.61%
DE							
Discount - %	100.00			100.00		100.00	
D-FERA							
Energy Charge- $/kWh							
Baseline - Summer	0.06947	0.04861	0.11808	0.02237	0.09571	0.11808	0.00%
- Winter	0.06947	0.04861	0.11808	0.02237	0.09571	0.11808	0.00%
101% - 130% of Baseline - Summer	0.06947	0.06794	0.13741	0.04170	0.09571	0.13741	0.00%

Phase 2 Residential and Small Commercial Rate Design Settlement Agrement

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates Based on Estimated Adjusted Revenue			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
- Winter	0.06947	0.06794	0.13741	0.04170	0.09571	0.13741	0.00%
131% - 200% of Baseline - Summer	0.06947	0.06794	0.13741	0.04170	0.09571	0.13741	0.00%
- Winter	0.06947	0.06794	0.13741	0.04170	0.09571	0.13741	0.00%
200% - 300% of Baseline - Summer	0.06947	0.17059	0.24006	0.21562	0.09571	0.31133	29.69%
- Winter	0.06947	0.17059	0.24006	0.21562	0.09571	0.31133	29.69%
Over 300% of Baseline	0.06947	0.20559	0.27506	0.25062	0.09571	0.34633	25.91%
- Winter	0.06947	0.20559	0.27506	0.25062	0.09571	0.34633	25.91%
Basic Charge - $/day							
Single-Family Residence	0.029	0.000	0.029	0.029		0.029	0.00%
Multi-Family Residence	0.022	0.000	0.022	0.022		0.022	0.00%
Minimum Charge - $/day							
Single Family Residence	0.059	0.000	0.059	0.059		0.059	0.00%
Multi-Family Residence	0.044	0.000	0.044	0.044		0.044	0.00%
DM							
Diversity Adjustment - $/unit/day	0.100	0.000	0.100	0.170		0.170	70.00%
Agricultural Employee Housing Discount - %	100.00			100		100.00	
DMS-1							
Submeter Discount - $/unit/day	(0.086)	0.000	(0.086)	(0.097)		(0.097)	-12.79%
Diversity Adjustment - $/unit/day	0.100	0.000	0.100	0.170		0.170	70.00%
Basic Charge - $/unit/day	0.029	0.000	0.029	0.022		0.022	-24.14%
Minimum Average Rate - $/kWh	0.03776	0.00000	0.03776	0.02737		0.02737	-27.52%
DMS-2							
Submeter Discount - $/unit/day	(0.300)	0.000	(0.300)	(0.340)		(0.340)	-13.33%
Diversity Adjustment - $/unit/day	0.100	0.000	0.100	0.170		0.170	70.00%
Basic Charge - $/unit/day	0.029	0.000	0.029	0.022		0.022	-24.14%
Minimum Average Rate - $/kWh	0.03776	0.00000	0.03776	0.02737		0.02737	-27.52%
DMS-3							
Basic Charge Adjust - $/unit/day	0.029	0.000	0.029	0.029	0.000	0.029	0.00%
DS							
Summer Season Premium - $/kWh/day	0.030	0.040	0.070	0.030	0.040	0.070	0.00%
Winter Season Discount - $/kWh/day	(0.030)	(0.040)	(0.070)	(0.030)	(0.040)	(0.070)	0.00%
California Alternate Rates for Energy Discount - %	100.00		100.00	100.00		100.00	
TOU-D-T							
Energy Charge - $/kWh							
Summer Season							
Baseline (BL) - On-Peak				0.02730	0.27401	0.30131	
101% - 130% of BL - On-Peak				0.02730	0.27401	0.30131	
131% - 200% of BL - On-Peak				0.20993	0.24721	0.45714	
200% - 300% of BL - On-Peak				0.20993	0.24721	0.45714	
Over 300% of BL - On-Peak				0.20993	0.24721	0.45714	
Baseline (BL) - Off-Peak				0.02730	0.08041	0.10771	
101% - 130% of BL - Off-Peak				0.02730	0.08041	0.10771	
131% - 200% of BL - Off-Peak				0.20993	0.08218	0.29211	
200% - 300% of BL - Off-Peak				0.20993	0.08218	0.29211	
Over 300% of BL - Off-Peak				0.20993	0.08218	0.29211	
Winter Season							
Baseline (BL) - On-Peak				0.02730	0.08865	0.11595	
101% - 130% of BL - On-Peak				0.02730	0.08865	0.11595	
131% - 200% of BL - On-Peak				0.20993	0.08321	0.29314	
200% - 300% of BL - On-Peak				0.20993	0.08321	0.29314	
Over 300% of BL - On-Peak				0.20993	0.08321	0.29314	
Baseline (BL) - Off-Peak				0.02730	0.06643	0.09373	
101% - 130% of BL - Off-Peak				0.02730	0.06643	0.09373	
131% - 200% of BL - Off-Peak				0.20993	0.06755	0.27748	
200% - 300% of BL - Off-Peak				0.20993	0.06755	0.27748	
Over 300% of BL - Off-Peak				0.20993	0.06755	0.27748	

Phase 2 Residential and Small Commercial Rate Design Settlement Agrement

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates Based on Estimated Adjusted Revenue			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
Customer Charge - $/day				0.029	0.000	0.029	
~~TOU Meter Charge - $/day~~				~~0.523~~	~~0.000~~	~~0.523~~	
California Alternate Rates for Energy Discount - %				100.00	0.000	100.00	
TOU-EV							
Energy Charge - $/kWh							
Summer Season - On-Peak	0.09599	0.14193	0.23792	0.11814	0.17974	0.29788	25.20%
Off-Peak	0.09599	0.06121	0.15720	0.05798	0.05369	0.11167	-28.96%
Winter Season - On-Peak	0.09599	0.08367	0.17966	0.12590	0.09622	0.22212	23.63%
Off-Peak	0.09599	0.06398	0.15997	0.05798	0.05310	0.11108	-30.56%
TOU Meter Charge - $/day	0.159	0.000	0.159	0.029		0.029	-81.76%
Minimum Charge - $/day	0.172	0.000	0.172	0.171		0.171	-0.58%
GS-1							
Energy Charge - $/kWh							
Summer	0.04157	0.10789	0.14946	0.06106	0.13604	0.19710	31.88%
Winter	0.04157	0.10450	0.14607	0.06106	0.08604	0.14710	0.71%
Customer Charge - $/day	0.565	0.000	0.565	0.625		0.625	10.62%
Three Phase Service - $/day	0.138	0.000	0.138	0.031		0.031	-77.54%
~~TOU Option Meter Charge - $/day~~	~~0.609~~	~~0.000~~	~~0.609~~	~~0.366~~		~~0.366~~	~~-39.90%~~
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	(0.00026)	(0.00227)	(0.00253)	(0.00047)	(0.00217)	(0.00264)	-4.50%
above 50 kV	(0.00856)	(0.00494)	(0.01350)	(0.01474)	(0.00484)	(0.01958)	-45.04%
California Alternate Rates for Energy Discount - %	100.00	0.00	100.00	100.00		100.00	0.00%
GS-APS (Schedules: GS-1 and TOU-GS-1)							
Air Conditioning Cycling Credit - $/ton/summer season day							
30% Cycling	(0.014)	0.000	(0.014)	(0.053)	0.000	(0.053)	-278.57%
40% Cycling	(0.042)	0.000	(0.042)	(0.069)	0.000	(0.069)	-64.29%
50% Cycling	(0.070)	0.000	(0.070)	(0.091)	0.000	(0.091)	-30.00%
100% Cycling	(0.200)	0.000	(0.200)	(0.370)	0.000	(0.370)	-85.00%
GS-APS (Schedules: GS-2, TOU-GS-3, or TOU-8)							
Air Conditioning Cycling Credit - $/ton/summer season month							
30% Cycling	(0.42)	0.00	(0.42)	(1.62)	0.00	(1.62)	-285.71%
40% Cycling	(1.25)	0.00	(1.25)	(2.11)	0.00	(2.11)	-68.80%
50% Cycling	(2.10)	0.00	(2.10)	(2.77)	0.00	(2.77)	-31.90%
100% Cycling	(6.00)	0.00	(6.00)	(11.25)	0.00	(11.25)	-87.50%
GS-APS-E (Schedules: GS-1 and TOU-GS-1)							
Air Conditioning Cycling Credit - $/ton/summer season day							
30% Cycling	(0.028)	0.000	(0.028)	(0.064)	0.000	(0.064)	-128.57%
40% Cycling	(0.084)	0.000	(0.084)	(0.084)	0.000	(0.084)	0.00%
50% Cycling	(0.140)	0.000	(0.140)	(0.106)	0.000	(0.106)	24.29%
100% Cycling	(0.400)	0.000	(0.400)	(0.416)	0.000	(0.416)	-4.00%
TOU-EV-3							
Energy Charge - $/kWh							
Summer Season On-Peak	0.05429	0.19715	0.25144	0.06106	0.24229	0.30335	20.65%
Off-Peak	0.05429	0.07532	0.12961	0.06106	0.05634	0.11740	-9.42%
Winter Season On-Peak	0.05429	0.10409	0.15838	0.06106	0.11324	0.17430	10.05%
Off-Peak	0.05429	0.07481	0.12910	0.06106	0.05187	0.11293	-12.52%
Customer Charge - $/day	0.565	0.000	0.565	0.625		0.625	10.62%
~~TOU Meter Charge - $/day~~	~~0.252~~	~~0.000~~	~~0.252~~	~~0.366~~		~~0.366~~	~~45.24%~~

Phase 2 Residential and Small Commercial Rate Design Settlement Agrement

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates Based on Estimated Adjusted Revenue			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-1							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.05429	0.14968	0.20397	0.06106	0.33856	0.39962	95.92%
Mid-peak	0.05429	0.11926	0.17355	0.06106	0.14384	0.20490	18.07%
Off-Peak	0.05429	0.07938	0.13367	0.06106	0.05900	0.12006	-10.18%
Winter Season							
Mid-peak	0.05429	0.12232	0.17661	0.06106	0.08316	0.14422	-18.34%
Off-Peak	0.05429	0.08352	0.13781	0.06106	0.05581	0.11687	-15.19%
Customer Charge - $/day	0.565	0.000	0.565	0.625	0.000	0.625	10.62%
~~TOU Meter Charge - $/day~~	~~0.252~~	~~0.000~~	~~0.252~~	~~0.366~~	~~0.000~~	~~0.366~~	~~45.24%~~
Three-Phase Service - $/day	0.138	0.000	0.138	0.031	0.000	0.031	-77.54%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	(0.00026)	(0.00227)	(0.00253)	(0.00047)	(0.00217)	(0.00264)	-4.50%
above 50 kV	(0.00856)	(0.00494)	(0.01350)	(0.01474)	(0.00484)	(0.01958)	-45.04%
California Alternate Rates for Energy Discount - %	100.00		100.00	100.00		100.00	0.00%
PPP							
Energy Charge - $/kWh							
PEAK Plus Event Time Period (2pm-6pm)							
PEAK Plus Event Credit - On-Peak							
California Alternate Rates for Energy Discount - %	100.00						
~~< 200 kW CPP rider~~							
~~2 - 6pm CPP event Energy Charge - $/kWh~~				~~0.00000~~	~~1.05828~~	~~1.05828~~	
~~NON Event $/kWh Credit~~							
~~Residential~~				~~0.00000~~	~~(0.02857)~~	~~(0.02857)~~	
~~GS-1~~				~~0.00000~~	~~(0.01034)~~	~~(0.01034)~~	
~~GS-2~~				~~0.00000~~	~~(0.00964)~~	~~(0.00964)~~	
~~Peak Time Rebate (PTR) - $/kWh~~				~~0.00000~~	~~(0.75000)~~	~~(0.75000)~~	
~~Peak Time Rebate (PTR) with PCT - $/kWh~~				~~0.00000~~	~~(1.25000)~~	~~(1.25000)~~	
Optional CPP rider < 200 kW							
CPP Event Energy Charge - $/kWh							
DOMESTIC				0.00000	1.36229	1.36229	
DOMESTIC CARE				0.00000	1.36229	1.36229	
GS-1				0.00000	1.36229	1.36229	
Summer Non-Event Energy Credit - $/kWh							
DOMESTIC				0.00000	(0.04032)	(0.04032)	
DOMESTIC CARE				0.00000	(0.03798)	(0.03798)	
GS-1				0.00000	(0.04044)	(0.04044)	

Phase 2 Residential and Small Commercial Rate Design Settlement Agreement

Note: Residential rates based on five cent Tier 3 - Tier 5 differential and baseline allocations set at 50% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008					Settlement Rates Based on Estimated Adjusted Revenue			
	Delivery	URG	DWR	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
D									
Energy Charge- $/kWh									
Baseline - Summer	0.07217	0.03412	0.08614	0.04861	0.12078	0.02411	0.09566	0.11977	-0.84%
- Winter	0.07217	0.03412	0.08614	0.04861	0.12078	0.02411	0.09566	0.11977	-0.84%
101% - 130% of Baseline - Summer	0.07217	0.06091	0.08614	0.06794	0.14011	0.04344	0.09566	0.13910	-0.72%
- Winter	0.07217	0.06091	0.08614	0.06794	0.14011	0.04344	0.09566	0.13910	-0.72%
131% - 200% of Baseline - Summer	0.07217	0.15468	0.08614	0.13559	0.20776	0.17859	0.09566	0.27425	32.00%
- Winter	0.07217	0.15468	0.08614	0.13559	0.20776	0.17859	0.09566	0.27425	32.00%
200% - 300% of Baseline - Summer	0.07217	0.20319	0.08614	0.17059	0.24276	0.20359	0.09566	0.29925	23.27%
- Winter	0.07217	0.20319	0.08614	0.17059	0.24276	0.20359	0.09566	0.29925	23.27%
Over 300% of Baseline	0.07217	0.25170	0.08614	0.20559	0.27776	0.22859	0.09566	0.32425	16.74%
- Winter	0.07217	0.25170	0.08614	0.20559	0.27776	0.22859	0.09566	0.32425	16.74%
Basic Charge - $/day									
Single-Family Residence	0.029			0.000	0.029	0.029		0.029	0.00%
Multi-Family Residence	0.022			0.000	0.022	0.022		0.022	0.00%
Minimum Charge - $/day									
Single Family Residence	0.059			0.000	0.059	0.059		0.059	0.00%
Multi-Family Residence	0.044			0.000	0.044	0.044		0.044	0.00%
D-CARE									
Energy Charge - $/kWh									
Baseline - Summer	0.03672	0.03412	0.08614	0.04861	0.08533	(0.01032)	0.09566	0.08534	0.01%
- Winter	0.03672	0.03412	0.08614	0.04861	0.08533	(0.01032)	0.09566	0.08534	0.01%
101% - 130% of Baseline - Summer	0.03874	0.06091	0.08614	0.06794	0.10668	0.01103	0.09566	0.10669	0.01%
- Winter	0.03874	0.06091	0.08614	0.06794	0.10668	0.01103	0.09566	0.10669	0.01%
131% - 200% of Baseline - Summer	0.02301	0.15468	0.08614	0.13559	0.15860	0.10436	0.09566	0.20002	26.11%
- Winter	0.02301	0.15468	0.08614	0.13559	0.15860	0.10436	0.09566	0.20002	26.11%
200% - 300% of Baseline - Summer	(0.01199)	0.20319	0.08614	0.17059	0.15860	0.10436	0.09566	0.20002	26.11%
- Winter	(0.01199)	0.20319	0.08614	0.17059	0.15860	0.10436	0.09566	0.20002	26.11%
Over 300% of Baseline	(0.04699)	0.25170	0.08614	0.20559	0.15860	0.10436	0.09566	0.20002	26.11%
- Winter	(0.04699)	0.25170	0.08614	0.20559	0.15860	0.10436	0.09566	0.20002	26.11%
Basic Charge - $/day									
Single-Family Residence	0.023			0.000	0.023	0.023		0.023	0.00%
Multi-Family Residence	0.017			0.000	0.017	0.017		0.017	0.00%
Minimum Charge - $/day									
Single Family Residence	0.047			0.000	0.047	0.047		0.047	0.00%
Multi-Family Residence	0.034			0.000	0.034	0.034		0.034	0.00%

Appendix B
Monthly and Annual Reports on Arrearages and Shutoffs

Monthly Reports Required By Paragraph 4.c

SCE shall provide the following reports on a monthly basis to the Director of the Energy Division for the period January 2009 through December 2011:

Data Points	Data Description / Comments
Total Number of Residential Accounts	Total number of customers on the residential rate as of reporting month
Total Number of Residential Accounts in Arrears	Total number of residential customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of Accounts in Arrears (Residential)	Residential customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of Residential Accounts Sent Notice of Disconnection	Number of residential customer accounts sent a final call notice if bill is not paid by day 51
Total Number of Residential Disconnections for Non-Payment	Number of residential customer accounts disconnected for non payment of energy account on or about day 53
Total Number of Residential Accounts Having Service Restored After Discontinuance for Non-Payment	Number of residential customer accounts restored after service was discontinued due to non-payment of energy account
Total Number of California Alternate Rates for Energy (CARE) Accounts	Total number of residential customers on CARE rate as of reporting month
Total Number of CARE Accounts in Arrears	Total number of residential CARE customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of CARE Accounts in Arrears	Residential CARE customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of CARE Accounts Sent Notice of Disconnection	Number of residential CARE customer accounts sent a final call notice if bill is not paid by day 51
Total Number of CARE Disconnections for Non-Payment	Number of residential CARE customer accounts disconnected for non payment of energy account on or about day 53
Total Number of CARE Accounts Having Service Restored After Discontinuance for Non-Payment	Number of residential CARE customer accounts restored after service was discontinued due to non-payment of energy account
Total Number of Family Electric Rate Assistance Program (FERA) Accounts	Total number of residential customers on FERA as of reporting month
Total Number of FERA Accounts in Arrears	Total number of residential FERA customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of FERA Accounts in Arrears	Residential FERA customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of FERA Accounts Sent Notice of Disconnection	Number of residential FERA customer accounts sent a final call notice if bill is not paid by day 51
Total Number of FERA Disconnections for Non-Payment	Number of residential FERA customer accounts disconnected for non payment of energy account on or about day 53
Total Number of FERA Accounts Having Service Restored After Discontinuance for Non-Payment	Number of residential FERA customer accounts restored after service was discontinued due to non-payment of energy account

Annual Reports Required By Paragraph 4.c.

SCE shall provide the following reports on an annual basis to the Director of the Energy Division for the period January 2009 through December 2011 on February 1 of each year, covering write-offs for the previous calendar year (or as soon thereafter as the data becomes available):

1. Dollar Value of Residential Accounts Written Off as Uncollectible, Following Shutoff for Nonpayment

2. Dollar Value of CARE Accounts Written Off as Uncollectible, Following Shutoff for Nonpayment.

Appendix C
Baseline Allocations

Table C-1
Baseline Allocations Effective February 1, 2001 (AB1X Limits)

Allocations Based On Average Consumption 1989 - 1992					
Summer kWh Per Day			Winter kWh Per Day		
Baseline Region	Basic	All Electric	Baseline Region	Basic	All Electric
10	9.1	10.0	10	9.2	16.2
13	15.8	29.0	13	11.0	32.8
14	14.2	20.3	14	10.6	29.5
15	42.7	42.7	15	8.8	27.4
16	9.2	14.3	16	10.1	28.5
17	13.1	16.9	17	10.5	24.1

Note: Baseline allocation for Basic customers set at 55%. Baseline allocation for All-Electric customers set at 60% for summer and 70% for winter

Table C-2

Current Baseline Allocations

Allocations Based on Average Consumption 1999 - 2001					
Summer kWh Per Day			Winter kWh Per Day		
Baseline Region	Basic	All Electric	Baseline Region	Basic	All Electric
10	10.2	10.0	10	10.1	16.2
13	19.4	29.0	13	12.4	32.8
14	17.0	20.6	14	11.5	29.5
15	47.6	42.7	15	9.8	27.4
16	10.0	14.3	16	10.7	28.5
17	15.4	16.9	17	11.7	24.1

Note: Following Baseline OIR, baseline allocation for Basic customers set at 60% with updated average consumption. All Electric customers' baseline allocation set at 70% for summer and winter.

Table C-3

Proposed Baseline Allocations (No AB1X Modifications)

Allocations Based on Average Consumption 2002 - 2005								
Summer kWh Per Day					Winter kWh Per Day			
Climate Zone	Baseline Region	Basic	All Electric		Climate Zone	Baseline Region	Basic	All Electric
5	10A	9.1	10.0		5	10A	9.2	16.2
6	10B	9.1	10.0		6	10B	9.2	16.2
8	10C	9.1	10.0		8	10C	9.2	16.2
13	13	16.4	29.0		13	13	11.0	32.8
14	14	14.3	20.3		14	14	10.6	29.5
15	15	42.7	42.7		15	15	8.8	27.4
16	16	10.1	14.3		16	16	10.1	28.5
9	17A	13.1	16.9		9	17A	10.5	24.1
10	17B	14.4	17.4		10	17B	10.5	24.1

Note: Baseline allocation for Basic customers set at 50%. Baseline allocation for All Electric customers set at 60% for summer and 70% for winter. AB1X baseline allocations set minimum baseline allocations. See Paragraph 4.b.v of Settlement Agreement.

Table C-4

Proposed Baseline Allocations (With AB1X Modifications)

Allocations Based on Average Consumption 2002 - 2005								
Summer kWh Per Day					Winter kWh Per Day			
Climate Zone	Baseline Region	Basic	All Electric		Climate Zone	Baseline Region	Basic	All Electric
5	10A	9.1	10.0		5	10A	9.8	16.7
6	10B	9.2	10.0		6	10B	9.6	16.2
8	10C	10.2	10.0		8	10C	9.2	16.2
13	13	18.6	29.0		13	13	11.0	32.8
14	14	16.1	20.3		14	14	10.6	29.5
15	15	43.9	42.7		15	15	9.0	27.4
16	16	11.5	14.3		16	16	10.9	28.5
9	17A	13.9	16.9		9	17A	10.5	24.1
10	17B	16.0	17.4		10	17B	10.5	24.1

Note: Baseline allocation for Basic Customers set at 55%. Baseline allocation for All-Electric customers set at 60% for summer and 70% for winter. AB1X baseline allocations set minimum baseline allocations. See Paragraph 4.b.v of Settlement Agreement

ATTACHMENT D

Medium and Large Power Rate Group Rate Design 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, And Design Rates	))))	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	))))	Application 07-12-020 (Filed December 21, 2007)

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Dated: January 29, 2009

#1599257.v7

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Medium And Large Power Rate Group Rate Design Settlement 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), Federal Executive Agencies (FEA); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); the Solar Alliance; the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA); Debenham Energy (Debenham), the Solar Alliance, and the Energy Producers and Users Coalition (EPUC); (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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. 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.

c. 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.

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

e. Energy Users Forum 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 either investor-owned utility and/or municipal utility service areas, taking service on rate schedules for accounts with demand above 100 kW. EUF represents entities that have accounts taking service on all SCE rate schedules from GS-2 to TOU-8 Subtransmission.

f. BOMA consists of associations of commercial real estate professionals that own, manage, or otherwise service commercial office buildings in SCE's service territory and within California. BOMA members own or manage in excess of 600 million square feet of commercial office space that is occupied by small and medium sized businesses.

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

h. Debenham is a privately owned limited liability company that provides renewable energy consulting services, developments for its own account, and assistance for other private and public entities with development, ownership, and financing of distributed generation projects in California, primarily utilizing utility scale wind energy technologies.

i. EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Conoco Phillips Company, Shell Oil Products US, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

2. Recitals

a. In Phase 2 of SCE's 2009 General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners, including the Settling Parties served their initial testimony on October 31, 2008.

e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Medium and Large Power rate groups as indicated in Paragraph 4 of this Agreement.

3. Definitions

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

b. “Backup Service” is the electric service provided by SCE to a customer who has an on-site generating facility during unscheduled outages of the on-site generator.

c. “BIP” or Base Interruptible Program means the rate schedule applicable to customers with demands in excess of 200 kW who receive a credit applied to their summer and winter Time-Related Demand Charges in return for the customer’s agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.

d. “Capacity Reservation Charge” means the charge assessed to Schedule S customers based on the customer’s designated kW level of Standby Demand.

e. “Cold Ironing” means the provision of electrical power for lights, heating, machinery or other needs of an ocean-going vessel at the Port of Long Beach or Port of Hueneme as replacement for the vessel’s auxiliary internal combustion engines or to a truck at truck stops where the truck’s internal combustion engine is turned off. For purposes of eligibility, the electric usage for Cold Ironing must be separately metered and 90 percent of the metered load must displace power generation associated with vessels or trucks that would otherwise be provided by internal combustion generation on the vessel or the truck.

f. “Critical Peak Pricing” means a dynamic rate that allows a short-term price increase of a predetermined level to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the event days are not predetermined.

g. “Settling Parties” means SCE, EUF, CMTA, CLECA, FEA, BOMA, Solar Alliance, Debenham, and EPUC.

h. “Supplemental Service” is the service provided by SCE to a customer who has an on-site generating facility for the portion of the customer’s load that is regularly provided by SCE as if the customer was a full-service customer.

i. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to rate schedules in the Large Power and Medium Power Rate Groups. Energy Charges recover a portion of SCE's costs for delivery service and generation. TOU utility retained generation (URG) Energy Charges will be set residually such that the weighted average of URG and DWR Energy Charges provide a price signal consistent with marginal cost differentials in TOU energy rates.

j. "Customer Charges" mean the dollar per month charges applicable to certain Medium and Large Power Rate Group rate schedules.

k. "Demand Charges" mean those charges that are comprised of Facilities-Related Demand Charges and Time-Related Demand Charges, which are based on the customer's maximum kW demand during the specified billing periods. Demand Charges recover a portion of SCE's delivery and generation costs.

l. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.* separately for generation versus distribution, and customer).

m. "Gross Nameplate Capacity" means the total gross generating capacity of a generator or a generating facility (as defined in SCE's Rule 21) as designated by the manufacturer (s) of the generators.

n. "Facilities-Related Demand Charges" are charges applied to customers' monthly peak demands not differentiated by TOU or by season that are designed to recover certain transmission and distribution costs that are defined to be unrelated to generation system peak or coincident peak usage.

o. "Time-Related Demand Charges" are generation-related, marginal cost based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities or loss of load expectations during the TOU periods. Scaled TOU marginal energy costs along with the Time-Related Demand Charges are designed to collect the allocated revenue requirement for SCE's base generation and fuel and purchased power costs.

p. "Large Power Rate Groups" means the following SCE rate groups in which demands are 500 kW or greater and are differentiated by service voltage as follows: TOU-8-Subtransmission (TOU-8-Sub), which is for service above 50 kV; TOU-8-Primary (TOU-8-Pri), which is for service from 2 kV to 50 kV; and TOU-8-Secondary (TOU-8-Sec), which is for service below 2 kV.

q. "Medium Power Rate Groups" means the following rate groups: GS-2 and TOU-GS-3. Demands for the GS-2 rate group are from 20 kW to 199 kW. Demands for the TOU-GS-3 rate group are from 200 kW to 499 kW.

r. "Permanent Load Shift" means technologies that are installed to allow customers to shift load that would otherwise occur during peak periods to off-peak periods on a permanent basis.

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

t. "Renewable Distributed Generation Technologies" means solar, wind, fuel cells, and any other renewable generation technology as defined in the Statewide California Solar initiative, the Self-Generation Incentive Program, or their successors.

u. "SCE RECC" means the method used by SCE to determine marginal customer costs for each rate group in Exhibit SCE-02 (Updated), dated June 27, 2008.

v. "Standby Demand" is the kW level of service designated by a Schedule S customer that SCE will provide during outage periods for a Schedule S customer's generating facility.

w. "Commission" or "CPUC" means the California Public Utilities Commission.

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 Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. **Common Pricing Principles**

1. **Customer Charges**

Except as otherwise specified in this Agreement, Customer Charges (SCE RECC basis) shall be set at the full EPMC level for customers with demands of 20 kilowatts (kW) or more who are served on TOU rate schedules effective October 1, 2009. Customer Charges (SCE RECC basis) for non-TOU rate schedules, *e.g.* Schedule GS-2, where Customer Charges are not currently set at the full EPMC level shall be increased by a maximum of 20 percent of the difference between the current Customer Charge and the full EPMC level effective October 1, 2009.

2. **Rate Structure**

   The current rate structure, consisting of Customer Charges, Energy Charges, and Demand Charges shall be maintained for all applicable rate schedules with the exception of Schedule GS-2-TOU (Option B), where on-peak and mid-peak Time-Related Demand Charges shall now apply.

3. **Implementing Revenue Changes in Rates**

   Changes to Customer Charges, Energy Charges, and Demand Charges shall be implemented on a Functional SAPC allocation basis whenever changes to SCE's authorized distribution and generation revenue requirements are implemented.

4. **Non-Generation Related Energy Charges**

   Energy Charges that are designed to recover revenues associated with transmission, distribution, public purpose programs, nuclear decommissioning, CARE balancing account, the California Department of Water Resources bonds, and the California Public Utilities Commission reimbursement fee shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Agreement, which was filed January 9, 2009.

5. **Demand Charges**

   Demand Charges shall be differentiated by season. However, the seasonality, and in some cases time differentiation, shall be retained in design of the Time-Related Demand Charges only, with no seasonal or TOU differences in the Facilities-Related Demand Charges.

6. **Voltage Discounts**

   Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting the lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the Medium and Large Power Rate Groups.

7. **CPP Program Design and Revenue Treatment**

   a. **CPP Design**

      SCE's CPP tariff shall allow no more than 15 events per year, nor less than 9 events per year, but is designed to be activated for 12 events per year on non-holiday summer weekdays and may occur only during the time period from 2:00 p.m. to 6:00 p.m. The CPP rate design structure, consisting of CPP energy adders and demand charge credits, shall be implemented as described by SCE's testimony in Exhibit SCE-04 (updated).

   b. **CPP Bill Protection**

      A customer who is subject to the CPP tariff (regardless of demand level) shall be provided bill protection such that bills under CPP for the first 12 months shall not exceed bills calculated on the customer's otherwise applicable tariff (OAT) provided the customer remains on the CPP tariff for a full year. Customers who do not remain on the CPP tariff for a full year shall forfeit any bill protection credits. SCE shall track the bill protection revenue deficiency by rate group and assign subsequent collection of the revenue deficiency to bundled service customers within the corresponding rate groups in a subsequent rate change proceeding, such as SCE's annual ERRA proceeding.

c. **CPP Revenue Allocation Impacts**

An undercollection of revenues relative to the design of the CPP rate may occur when fewer than twelve events per year are called, and an overcollection may occur when the number of called events is greater than twelve events per year. In order to minimize and account for revenue imbalances resulting from this variation, the Settling Parties agree that the minimum number of called events shall be nine events and that the undercollection or overcollection resulting from the difference between actual called events and twelve events as designed shall be assigned to the summer on-peak and mid-peak periods as a flat cent per kWh surcharge in the subsequent annual period for the CPP participants within each rate group that is responsible for the amount of the revenue imbalance.

8. **Demand Response Credits**

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, BIP, APS, and CPP shall be as proposed by SCE testimony in Exhibit SCE-04 (Updated), dated June 27, 2008. Customers enrolled in BIP and APS shall not be eligible for service on CPP rates.

9. **Illustrative Rates**

Rates for the Medium and Large Power Rate Groups shall be designed consistent with the illustrative rates in Appendix A.

b. **Large Power Rate Groups**

1. **New Schedules**

a. **Default CPP**

Schedule TOU-8 with the associated CPP components shall be the default rate schedule for commercial and industrial customers with demands greater than 500 kW. Schedules TOU-8-CPP-GCCD and TOU-8-VCD shall be eliminated. Customers may opt out from the CPP tariff upon notice as required under SCE's tariffs.

b. **Schedule TOU-8, Option A**

Schedule TOU-8, Option A, shall be offered as an alternate rate for customers with demands greater than 500 kW who employ Cold Ironing or Permanent Load Shift technologies.

i. To be eligible for the Cold Ironing option, the customer must comply with any applicable requirements of Rule 18.

ii. Rates for Schedule TOU-8, Option A, shall be structured to recover all generation-related capacity costs through volumetric energy charges on a cent per kWh basis. No changes will be made to the structure for recovering delivery-related demand charges.

c. **Schedule TOU-8, Option B**

Schedule TOU-8 Option B shall be the OAT for customers in the Large Power Rate Groups (who opt out of the default TOU-8 rate schedule with CPP components or who are ineligible for CPP rates) and shall include Customer

Charges, Energy Charges, and Demand Charges, designed as specified in this Agreement for the Large Power Rate Groups.

d. **Experimental Schedule For Renewable Generating Technologies**

An experimental rate shall be offered as an optional rate schedule for customers with demands greater than 20 kW but not exceeding four megawatts (MW) and who employ Renewable Distributed Generation Technologies. SCE will offer Schedule TOU-8-R to customers in the Large Power Rate Groups and similar rate structures to customers in the GS-2 and TOU-GS-3 rate groups under Schedules GS-2-TOU-R, and TOU-GS-3-R respectively. Participation on these rate schedules will be limited to a cumulative installed distributed generation output capacity of 150 MW for all eligible rate groups.

i. Eligible customers must install, own, or operate an eligible onsite Renewable Distributed Generation Technologies system with a net capacity that is 15 percent or greater than the customer's annual peak demand.

ii. Rates for Schedules TOU-8-R, TOU-GS-3-R, and GS-2-TOU-R shall be structured to recover all generation-related capacity costs through volumetric energy charges on a cent per kWh basis in a manner that maintains the same TOU allocation of generation revenue recovery.

iii. The distribution component of the Facilities-Related Demand Charge shall be set at 50 percent of the total Facilities-Related Demand Charge for the customer's otherwise-applicable tariff less the transmission-related demand charge. If the transmission-related demand charge is more than 50 percent of the total Facilities-Related Demand Charge, then the distribution component of the Facilities-Related Demand Charge will be set at 50 percent of the comparable distribution component in the customer's otherwise applicable tariff. The revenue deficiency resulting from this adjustment shall be collected by a non-time differentiated, cent per kWh volumetric charge. FERC jurisdictional transmission-related demand charges shall not be affected by this Agreement.

iv. SCE will offer experimental Schedules TOU-8-R, TOU-GS-3-R, and GS-2-TOU-R through the three-year term of SCE's 2009 GRC until rates are implemented in Phase 2 of SCE's 2012 GRC when the distribution Facilities-Related Demand Charges will be redesigned to reflect these customer's actual contribution to the distribution system costs. Customers who were served on these rate schedules prior to implementation of new rates in SCE's 2012 GRC shall be grandfathered, but the schedules shall be subject to redesign.

v. Prior to SCE's 2012 GRC, SCE will conduct a study to determine solar customers' contribution to the distribution and generation system peaks and the effect of such contribution on revenue allocation.

2. **Other Schedules and Options**

   a. Schedule TOU-8-BU shall be retained with charges modified consistent with other schedules in the Large Power Rate Groups.

   b. As specified in Appendix E to Exhibit SCE-04 (Updated), dated June 27, 2008, the method for determining power factor adjustment rates will be revised to more closely reflect SCE's cost of correcting poor power factor conditions. The power factor adjustment rates shall be $0.32 $/kVAR for service voltages greater than 50 kV and $0.27 $/kVAR for service voltages less than 50 kV.

   c. The real-time energy prices for Schedule RTP-2 shall be modified as described in Exhibit SCE-04 (Updated), dated June 27, 2008 consistent with the following: Schedule RTP-2 generation capacity charges shall reflect a generation marginal capacity cost of $114.10 per kW per year for the Large Power Rate Groups. Schedule RTP-2 Energy Charges shall reflect a generation marginal energy cost based on a natural gas burnertip price of $7.00 per million BTUs. Delivery service rates for Schedule RTP-2 shall be the delivery service rates from the customer's voltage-differentiated otherwise applicable tariff.

   d. The Optimal Billing Period shall be retained, allowing customers to align their billing and production cycles twice within a six-month period.

3. **Customer Charges**

   Effective October 1, 2009, estimated monthly Customer Charges shall be as follows:

Large Power Rate Groups
Estimated Monthly Customer Charges

Rate Group	Customer Charge
TOU-8-Sec	$542.25
TOU-8-Pri	$291.00
TOU-8-Sub	$2,232.25

4. **Time-Related Demand Charges**

Consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009, the estimated Time-Related Demand Charges set to recover the allocated generation revenues for TOU-8-Sec, TOU-8-Pri and TOU-8-Sub shall be as set forth in the table, below, subject to the applicable discount for transmission voltage level service. The Time-Related Demand Charges for the TOU-8-Pri and TOU-8-Sub rate groups shall be established consistent with the values for marginal generation capacity cost, marginal energy cost, relative loss-of-load expectation and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009. The Time-Related Demand Charges for the TOU-8-Sec rate group shall be established in the same manner as for the TOU-8-Pri and TOU-8-Sub rate groups, with the exception of an assumed marginal generation capacity cost of $95 per kW per year, instead of $114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. To maintain consistent TOU generation cost recovery, the deficiency from the SCE generation revenue allocated to the TOU-8-Sec rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the summer season on-peak and mid-peak Energy Charges for the TOU-8-Sec rate group in a manner that maintains the same TOU allocation of generation revenue recovery.

Large Power Rate Groups
Estimated Time-Related Demand Charges

	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak $/kW	19.73	23.82	20.26
Summer Mid-Peak $/kW	5.56	6.68	5.35

On October 1, 2009, these estimated Time-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Time-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

5. **Facilities-Related Demand Charges**
The estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission revenues) for TOU-8-Sec, TOU-8-Pri, and TOU-8-Sub shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design testimony (Exhibit SCE-04 (Updated)) as follows, subject to the applicable discount for transmission voltage level service:

Large Power Rate Groups
Estimated Facilities-Related Demand Charges

	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
$/kW	11.70	10.96	4.47

On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

6. **Energy Charges**

Total generation-related Energy Charges shall be established based on marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to each Large Power Rate Group. With the exception of the TOU-8-Sec rate group (to be consistent with Paragraph 4.b.4, above) the estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal generation energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009.

c. **Medium Power Rate Groups**

1. **GS-2 Rate Group**

Customers with peak demands of 20 kW to 199 kW shall take service on a default basis on an applicable non-TOU rate schedule (Schedule GS-2) with eligibility to participate in a CPP tariff. (Customers with peak demands of less than 20 kW may also elect to take service on an applicable rate schedule in the GS-2 rate group.) Customers shall also have the option of taking service on a TOU rate schedule, *e.g.* Schedule GS-2-TOU, Option A or Option B.

2. **Schedule GS-2 and TOU Rate Structure**

For Schedule GS-2, the default rate structure shall consist of a monthly Customer Charge, seasonal Time-Related Demand Charge, a Facilities-Related Demand Charge, and seasonal Energy Charges.

a. **Customer and Meter Charges**

Effective October 1, 2009, the estimated Customer Charge shall be $114.25 per month. There shall be no incremental charge for TOU metering.

b. **Facilities-Related Demand Charge**

The estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission revenues) for the GS-2 rate group shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design testimony (Exhibit SCE-04 (Updated)) as shown in Attachment A. On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

c. **Time-Related Demand and Energy Charges**

The Time-Related Demand Charges for the GS-2 rate group shall be established in the same manner as for the TOU-8-Sec rate group, with an assumed marginal generation capacity cost of $95 per kW per year, instead of $114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The deficiency from the SCE generation revenue allocated to the GS-2 rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the summer season Energy Charges for Schedule GS-2 (non TOU option) or in the on-peak and mid-peak Energy Charges for Schedule GS-2 (TOU Options). With the exception of these adjustments, generation-related Energy Charges shall be established based on generation marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to the GS-2 rate group. The estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009.

3. **Bill Limiter**

   SCE shall retain the bill limiter provision of Schedule GS-2.

4. **TOU-GS-3 Rate Group**

   Customers with peak demands of 200 kW to 499 kW shall take service on Schedule TOU-GS-3 which includes the CPP components on a default basis. Customers may opt out to Schedule TOU-GS-3, Option B or other applicable tariffs. There shall be no incremental charge for TOU metering.

a. **Customer Charge**

Effective October 1, 2009, the estimated Customer Charge shall be set at $443.75 per month.

b. **Facilities-Related Demand Charge**

The Facilities-Related Demand Charges shall be determined the same as for the Large Power Rate Groups, depending on the service voltage level.

c. **Time-Related Demand and Energy Charges**

The Time-Related Demand Charges for the TOU-GS-3 rate group shall be established in the same manner as for the TOU-8-Sec rate group, with an assumed marginal generation capacity cost of $95 per kW per year, instead of $114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The deficiency from the SCE generation revenue allocated to the TOU-GS-3 rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the on-peak and mid-peak Energy Charges for Schedule TOU-GS-3 and its TOU options. With the exception of these adjustments, generation-related Energy Charges shall be established based on generation marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to the TOU-GS-3 rate group. The estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2

Revenue Allocation Settlement Agreement, effective October 1, 2009.

5. **SOP Option**

Schedule TOU-GS-3-SOP shall retain its existing rate and TOU period structure. SCE shall update Schedule TOU-GS-3-SOP Energy Charges and Demand Charges consistent with those charges established for Schedule TOU-GS-3, as specified in paragraph 4.c.2.a, b, and c, above.

6. **TOU-EV-4**

Schedule TOU-EV-4 off-peak Energy Charges will provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges as defined by D.07-11-052. On-peak Energy Charges will be set consistent with Schedule TOU-GS-3 on-peak Energy Charges but will reflect the different time-period definitions offered for the charging of commercial electric vehicles and incremental revenue recovery associated with the provided off-peak discount.

d. **Standby Rate Design**

Schedule S is the applicable rate schedule for customers who install on-site generation and receive electric service from SCE either as Supplemental, Backup, or Maintenance service. The Schedule S rate structure for Backup and Maintenance service shall consist of a Capacity Reservation Charge, a Customer Charge, Demand Charges, Time-Related Demand Charges, and Energy Charges.

1. **Customer Charges, Power Factor and Voltage Adjustments**

The Schedule S Customer Charge shall be equal to Customer Charge that applies to the OAT for the maximum demand level, *i.e.*, for maximum demands of 500 kW or less, or greater than

500 kW as differentiated by delivery voltage levels. Customer Charges for Schedule S customers taking both Backup and Supplemental service through a single delivery point shall be assessed solely on the customer's OAT.

The power factor adjustment shall be applied in accordance with the customer's OAT.

Schedule S customers served at higher voltage delivery levels than the design voltage level for their corresponding rate group shall receive a voltage discount in accordance with the customer's OAT.

2. **Capacity Reservation Charge**

   The level of Standby Demand shall be designated by the customer and shall be less than or equal to the Gross Nameplate Capacity of the customer's generating facility. SCE shall have the right to verify that the customer's designated Standby Demand does not exceed the Gross Nameplate Capacity of the customer's generating facility. The Standby Demand shall be charged the Capacity Reservation Charge which consists of: (1) a transmission component, which is established under FERC jurisdiction; and (2) if applicable, a distribution component. The distribution components of the Capacity Reservation Charge are determined by adjusting the voltage level $/kW-year marginal distribution costs by the applicable distribution Equal Percent of Marginal Cost (EPMC) revenue scalar. The distribution cost components are then adjusted by a voltage-differentiated, effective demand factor and illustrative results are shown, by voltage level, in the following table:

Voltage Level	Distribution $/kW-Year	Distribution Component of the Capacity Reservation Charge ($/kW-month)
Below 2 kV	$40.00	$4.00
From 2 kV to 50 kV	$39.00	$3.91
Above 50 kV but below 220 kV	$6.00	$0.58
At 220 kV	$0.00	$0.00

For customers taking only Backup Service, the Capacity Reservation Charge shall be in lieu of a Facilities-Related Demand Charge. A customer taking both Backup and Supplemental service shall be charged the Capacity Reservation Charge for Standby Demand and the OAT Facilities-Related Demand Charge for all facilities-related demand in excess of the Standby Demand. Customers who meet all the provisions of the Physical Assurance Contract and who schedule Maintenance Service under the terms of the Physical Assurance contract shall be exempt from the Capacity Reservation Charge under normal operations. The Capacity Reservation Charge and Backup Time–Related Demand Charges will however apply during the period the customer receives energy from SCE under the Maintenance Service provision of the Physical Assurance contract.

3. **Time-Related Demand Charges**

   A new Time-Related Demand Charge will apply to Backup Service. The generation demand-related charge shall be determined based on each voltage level's contribution to the top 100 hours peak demand and shall be assigned by TOU periods. Any revenue deficiency resulting from this lower, cost-based, generation demand charge for Backup Service is to be recovered through an increase in Energy Charges for customers within the OAT rate group in the corresponding TOU periods.

The Time-Related Demand Charges for the Schedule S TOU-8-Pri, TOU-8-Sub rate groups shall be designed consistent with the method specified in this Agreement for the Time-Related Demand Charges for the TOU-8-Pri and TOU-8-Sub rate groups. The Schedule S Time-Related Demand Charges for the TOU-8-Sec rate group shall be designed consistent with the method specified in this Agreement for the Time-Related Demand Charges for the TOU-8-Sec rate group.

a. **TOU-8-SUB, TOU-8-PRI, and TOU-8-SEC Time-Related Demand Charges**

The estimated Time-Related Demand Charges ultimately expected to result after implementation of a phased-in reduction, which is described in Paragraph 4.d.4, below, are as follows:

Standby
Estimated Time-Related Demand Charges

	Secondary	Primary	Subtransmission	Transmission
Summer On-Peak $/kW	12.59	13.43	11.79	11.67
Summer Mid-peak $/kW	3.27	3.40	2.18	2.16

b. **Adjustments To Time-Related Demand Charges**

Adjustments made to estimated Time-Related Demand Charges shall be consistent with the Phase 2 Revenue Allocation Settlement Agreement and the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

c. As early as practicable in 2011 the ratio of the Backup Service Time-Related Demand Charge to the Supplemental

Service Time-Related Demand Charge shall be maintained as indicated in the following table:

TOU Period	TOU-8-SEC	TOU-8-PRI	TOU-8-SUB
On-Peak	0.64	0.56	0.58
Mid Peak	0.59	0.51	0.41

4. **Phase-In of Reduced Time-Related Demand Charges For Backup Service**

The Settling Parties agree that in order to reflect the diversity of demand imposed by Backup customers, the Time-Related Demand Charges for Schedule S shall be assessed separately from other customers in the corresponding rate groups. This results in lower Time-Related Demand Charges than those determined for the customers served on the OAT for the corresponding rate group. The revenue deficiency resulting from applying lower Time-Related Demand Charges for Backup Service shall be offset by increasing the summer On-Peak and Mid-Peak Energy Charges for the OAT for the corresponding rate group (*e.g.*, the revenue deficiency resulting from lower Time-Related Demand Charges for TOU-8-Sub standby customers would be offset by increasing the Energy Charges on the OAT for TOU-8-Sub). In order to mitigate bill impacts, the Settling Parties agree that SCE should phase-in the reduction in Schedule S Time-Related Demand charges, with fifty percent of the reduction effective on or after October 1, 2009, and the remaining fifty percent reduction effective when SCE's 2011 ERRA revenue requirement changes go into effect.

5. **Energy Charges**

   All kWh usage, whether Supplemental, Backup, or Maintenance service will be billed at the Energy Rates on the customer's OAT.

6. **Supplemental Service Rates**

   All usage for Supplemental Service will be billed in accordance with the rates specified on the customer's OAT.

7. **Illustrative Rates**

   Rates for the Standby Rate Groups shall be designed consistent with the illustrative rates in Appendix A.

5. Implementation of Agreement

It is the intent of the 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 October 1, 2009.

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 Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

7. Signature Date

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

8. Regulatory Approval

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

9. Compromise Of Disputed Claims

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

10. 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.

11. Previous Communications

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties.

12. 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.

13. Effect Of Subject Headings

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

14. 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.

15. 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 Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ BRUCE REED

Title: Senior Attorney Date: 2/5/2009

FEDERAL EXECUTIVE AGENCIES

By: /s/ NORM FURUTA

Title: Associate Counsel Date: 2/3/2009

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ KEITH McCREA

Title: Attorney Date: 2/5/2009

ENERGY USERS FORUM

By: /s/ CAROLYN KEHREIN

Title: Consultant Date: 2/3/2009

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ WILLIAM BOOTH

Title: Attorney Date: 2/5/2009

BOMA

By: /s/ BILL F. ROBERTS

Title: President, Economic Sciences Corp. Date: 2/5/2009

SOLAR ALLIANCE

By: /s/ TOM BEACH

Title: Consultant Date: 2/5/2009

ENERGY PRODUCERS AND USERS COALITION

By: /s/ NORA SHERIFF

Title: Counsel Date: 2/5/2009

DEBENHAM ENERGY, LLC

By: /s/ DONALD C. LIDDELL

Title: Counsel Date: 2/5/2009

Appendix A

Illustrative Rates for Medium and Large Power Rate Schedules

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-2 (Non TOU Option)							
Energy Charge - $/kWh							
Summer	0.01613	0.06929	0.08542	0.01969	0.07964	0.09933	16.29%
Winter	0.01613	0.06176	0.07789	0.01969	0.06510	0.08479	8.86%
Summer Time Related Demand Charge - $/kW	0.00	18.62	18.62	0.00	21.11	21.11	13.37%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)	0.00	(0.56)	(0.56)	-40.00%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(1.55)	(1.55)	-49.04%
GS-2 (TOU Option A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01613	0.21879	0.23492	0.01969	0.34112	0.36081	53.59%
Mid-peak	0.01613	0.17469	0.19082	0.01969	0.13287	0.15256	-20.05%
Off-Peak	0.01613	0.04756	0.06369	0.01969	0.05486	0.07455	17.05%
Winter Season							
Mid-peak	0.01613	0.07556	0.09169	0.01969	0.07751	0.09720	6.01%
Off-Peak	0.01613	0.05111	0.06724	0.01969	0.05195	0.07164	6.55%
GS-2 (TOU Option B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01613	0.09106	0.10719	0.01969	0.12716	0.14685	37.00%
Mid-peak	0.01613	0.07224	0.08837	0.01969	0.08045	0.10014	13.32%
Off-Peak	0.01613	0.04756	0.06369	0.01969	0.05486	0.07455	17.05%
Winter Season							
Mid-peak	0.01613	0.07556	0.09169	0.01969	0.07751	0.09720	6.01%
Off-Peak	0.01613	0.05111	0.06724	0.01969	0.05195	0.07164	6.55%
Time Related Demand Charge - $/kW	0.00	18.62	18.62	0.00	0.00	0.00	
Summer Season							
On-Peak				0.00	18.50	18.50	
Mid-Peak				0.00	5.65	5.65	
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)	0.00	(0.56)	(0.56)	-40.00%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(1.55)	(1.55)	-49.04%
GS-2 (All Options)							
Customer Charge - $/month	94.65	0.00	94.65	114.25		114.25	20.71%
Facilities Related Demand Charge - $/kW	9.54	0.00	9.54	11.62		11.62	21.76%
Single Phase Service - $/month	(29.42)	0.00	(29.42)	(9.94)		(9.94)	66.21%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.14)		(0.14)	26.32%
above 50 kV	(6.24)	0.00	(6.24)	(4.28)		(4.28)	31.41%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00140)	(0.00140)	29.83%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00311)	(0.00311)	28.20%
CARE Energy Discount - %	100.00%			100.00%		100.00%	
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	
~~TOU Option Meter Charge - $/month~~							
~~Standard~~	~~18.43~~	~~0.00~~	~~18.43~~	~~21.23~~		~~21.23~~	~~15.19%~~
TOU-RTEM	158.83	0.00	158.83	88.48		88.48	-44.29%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-APS (Schedules: GS-2, TOU-GS-3, or TOU-8)							
Air Conditioning Cycling Credit - $/ton/summer season month							
30% Cycling	(0.42)	0.00	(0.42)	(1.62)	0.00	(1.62)	-285.71%
40% Cycling	(1.25)	0.00	(1.25)	(2.11)	0.00	(2.11)	-68.80%
50% Cycling	(2.10)	0.00	(2.10)	(2.77)	0.00	(2.77)	-31.90%
100% Cycling	(6.00)	0.00	(6.00)	(11.25)	0.00	(11.25)	-87.50%
GS-APS-E (Schedules: GS-2, TOU-GS-3, or TOU-8)							
Air Conditioning Cycling Credit - $/ton/summer season month							
30% Cycling	(0.84)	0.00	(0.84)	(1.93)	0.00	(1.93)	-129.76%
40% Cycling	(2.50)	0.00	(2.50)	(2.55)	0.00	(2.55)	-2.00%
50% Cycling	(4.20)	0.00	(4.20)	(3.21)	0.00	(3.21)	23.57%
100% Cycling	(12.00)	0.00	(12.00)	(12.64)	0.00	(12.64)	-5.33%
RTP-2							
Energy Charge - $/kWh							
Below 2 kV	0.01481	Variable*	Variable*	0.01785	Variable*	Variable*	
From 2 kV to 50 kV	0.01434	Variable*	Variable*	0.01734	Variable*	Variable*	
above 50 kV	0.01289	Variable*	Variable*	0.01499	Variable*	Variable*	
Customer Charge - $/month							
Below 2 kV	458.04	0.00	458.04	542.25	0.00	542.25	18.38%
From 2 kV to 50 kV	275.69	0.00	275.69	291.00	0.00	291.00	5.55%
above 50 kV	2,427.22	0.00	2,427.22	2,232.25	0.00	2,232.25	-8.03%
Facilities Related Demand Charge - $/kW							
Below 2 kV	10.77	0.00	10.77	11.70	0.00	11.70	8.64%
From 2 kV to 50 kV	10.21	0.00	10.21	10.96	0.00	10.96	7.36%
above 50 kV	2.80	0.00	2.80	4.47	0.00	4.47	59.78%
Voltage Discount, Hourly Rates - %							
From 2 kV to 50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
above 50 kV, but below 220 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
at 220 kV	0.00%	-1.21%	-1.21%	0.00%	-1.21%	-1.21%	
Voltage Discount, Facility-Related Demand - %							
at 220 kV	100.00%			100.00%		100.00%	
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32		0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27		0.27	50.00%
***See RTP Schedules for RTP-2 & PA-RTP**							
TOU-BIP Option - $/kW (Applicable: Average kW demand)							
Option A							
BIP Option Credit ($/KW)							
Below 2 kV - Summer Average On Peak	(17.89)	0.00	(17.89)	(21.11)		(21.11)	-18.00%
Summer Average Mid - Peak	(5.50)	0.00	(5.50)	(6.45)		(6.45)	-17.27%
Winter Average Mid - Peak	(2.02)	0.00	(2.02)	(1.32)		(1.32)	34.65%
Excess Energy Charge - $/kWh	10.21374	0.00000	10.21374	13.90079		13.90079	36.10%
From 2 kV to 50 kV - Summer Average On Peak	(17.48)	0.00	(17.48)	(20.74)		(20.74)	-18.65%
Summer Average Mid - Peak	(5.40)	0.00	(5.40)	(6.12)		(6.12)	-13.33%
Winter Average Mid - Peak	(1.98)	0.00	(1.98)	(1.28)		(1.28)	35.35%
Excess Energy Charge - $/kWh	9.99551	0.00000	9.99551	13.61036		13.61036	36.16%
above 50 kV - Summer Average On Peak	(16.84)	0.00	(16.84)	(19.56)		(19.56)	-16.15%
Summer Average Mid - Peak	(5.22)	0.00	(5.22)	(5.56)		(5.56)	-6.51%
Winter Average Mid - Peak	(1.90)	0.00	(1.90)	(1.13)		(1.13)	40.53%
Excess Energy Charge - $/kWh	9.63234	0.00000	9.63234	13.09434		13.09434	35.94%
Option B							
BIP Option Credit ($/KW)							
Below 2 kV - Summer Average On Peak	(16.45)	0.00	(16.45)	(19.74)		(19.74)	-20.00%
Summer Average Mid - Peak	(5.02)	0.00	(5.02)	(6.02)		(6.02)	-19.92%
Winter Average Mid - Peak	(1.93)	0.00	(1.93)	(1.22)		(1.22)	36.79%
Excess Energy Charge - $/kWh	10.21374	0.00000	10.21374	12.96442		12.96442	26.93%
From 2 kV to 50 kV - Summer Average On Peak	(16.10)	0.00	(16.10)	(19.31)		(19.31)	-19.94%
Summer Average Mid - Peak	(4.92)	0.00	(4.92)	(5.70)		(5.70)	-15.85%
Winter Average Mid - Peak	(1.89)	0.00	(1.89)	(1.19)		(1.19)	37.04%
Excess Energy Charge - $/kWh	9.99551	0.00000	9.99551	12.69398		12.69398	27.00%
above 50 kV - Summer Average On Peak	(15.52)	0.00	(15.52)	(18.34)		(18.34)	-18.17%
Summer Average Mid - Peak	(4.74)	0.00	(4.74)	(5.21)		(5.21)	-9.92%
Winter Average Mid - Peak	(1.82)	0.00	(1.82)	(1.05)		(1.05)	42.31%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

	Rates Effective December 2008			Settlement Rates			
Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
Excess Energy Charge - $/kWh	9.63234	0.00000	9.63234	12.21347		12.21347	26.80%
TOU-EV-3							
Energy Charge - $/kWh							
Summer Season On-Peak	0.05429	0.19715	0.25144	0.06106	0.24229	0.30335	20.65%
Off-Peak	0.05429	0.07532	0.12961	0.06106	0.05634	0.11740	-9.42%
Winter Season On-Peak	0.05429	0.10409	0.15838	0.06106	0.11324	0.17430	10.05%
Off-Peak	0.05429	0.07481	0.12910	0.06106	0.05187	0.11293	-12.52%
Customer Charge - $/day	0.565	0.000	0.565	0.625		0.625	10.62%
~~TOU Meter Charge - $/day~~	~~0.252~~	~~0.000~~	~~0.252~~	~~0.366~~		~~0.366~~	~~45.24%~~
TOU-EV-4							
Energy Charge - $/kWh							
Summer Season On-Peak	0.01613	0.12986	0.14599	0.01969	0.26253	0.28222	93.32%
Off-Peak	0.01613	0.04875	0.06488	0.01969	0.05247	0.07216	11.22%
Winter Season On-Peak	0.01613	0.06792	0.08405	0.01969	0.12233	0.14202	68.97%
Off-Peak	0.01613	0.04842	0.06455	0.01969	0.04815	0.06784	5.10%
Customer Charge - $/meter/month	94.65	0.00	94.65	114.25		114.25	20.71%
Facilities Related							
Demand Charge - $/kW	9.54	0.00	9.54	11.62		11.62	21.76%
Time Related							
Demand Charge - $/kW	0.00	18.62	18.62	0.00	21.11	21.11	13.37%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.14)	0.00	(0.14)	26.32%
above 50 kV	(6.24)	0.00	(6.24)	(4.28)	0.00	(4.28)	31.41%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)	0.00	(0.56)	(0.56)	-40.00%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(1.55)	(1.55)	-49.04%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00140)	(0.00140)	29.83%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00311)	(0.00311)	28.20%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-GS-3 (Option A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01525	0.29651	0.31176	0.01848	0.25634	0.27482	-11.85%
Mid-peak	0.01525	0.12675	0.14200	0.01848	0.12074	0.13922	-1.96%
Off-Peak	0.01525	0.05341	0.06866	0.01848	0.06493	0.08341	21.48%
Winter Season							
Mid-peak	0.01525	0.08943	0.10468	0.01848	0.06921	0.08769	-16.23%
Off-Peak	0.01525	0.05626	0.07151	0.01848	0.05402	0.07250	1.38%
Customer Charge - $/month	367.02	0.00	367.02	443.75	0.00	443.75	20.91%
Facilities Related							
Demand Charge - $/kW	9.86	0.00	9.86	12.47	0.00	12.47	26.50%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-3 (Option B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01525	0.10180	0.11705	0.01848	0.12190	0.14038	19.93%
Mid-peak	0.01525	0.08084	0.09609	0.01848	0.08948	0.10796	12.35%
Off-Peak	0.01525	0.05341	0.06866	0.01848	0.06493	0.08341	21.48%
Winter Season							
Mid-peak	0.01525	0.08295	0.09820	0.01848	0.06921	0.08769	-10.70%
Off-Peak	0.01525	0.05626	0.07151	0.01848	0.05402	0.07250	1.38%
Customer Charge - $/month	367.02	0.00	367.02	443.75	0.00	443.75	20.91%
Facilities Related							
Demand Charge - $/kW	9.86	0.00	9.86	12.47	0.00	12.47	26.50%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	16.36	16.36	0.00	16.01	16.01	-2.14%
Mid-Peak	0.00	5.61	5.61	0.00	3.80	3.80	-32.26%
Winter Season							
Mid-Peak	0.00	0.00					
Off-Peak	0.00	0.00					
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.23)	(0.23)	41.03%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(0.64)	(0.64)	38.46%
TOU-GS-3 (Both Options)							
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.18)	0.00	(0.18)	5.26%
above 50 kV	(6.25)	0.00	(6.25)	(5.66)	0.00	(5.66)	9.44%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00138)	(0.00138)	30.65%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00307)	(0.00307)	29.04%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
CARE Energy Discount - %	100.00		100.00	100.00		100.00	0.00%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2009 (50% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8 (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01481	0.09517	0.10998	0.01785	0.12967	0.14752	34.14%
Mid-peak	0.01481	0.07552	0.09033	0.01785	0.08537	0.10322	14.28%
Off-Peak	0.01481	0.04978	0.06459	0.01785	0.05739	0.07524	16.50%
Winter Season							
Mid-peak	0.01481	0.07750	0.09231	0.01785	0.07626	0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728	0.01785	0.05431	0.07216	7.26%
Customer Charge - $/month	458.04	0.00	458.04	542.25	0.00	542.25	18.38%
Facilities Related							
Demand Charge - $/kW	10.77	0.00	10.77	11.70	0.00	11.70	8.64%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.23	15.23	0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14	0.00	5.56	5.56	8.17%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8 (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01434	0.09652	0.11086	0.01734	0.09348	0.11082	-0.03%
Mid-peak	0.01434	0.07662	0.09096	0.01734	0.07794	0.09528	4.75%
Off-Peak	0.01434	0.05049	0.06483	0.01734	0.05596	0.07330	13.07%
Winter Season							
Mid-peak	0.01434	0.07864	0.09298	0.01734	0.07431	0.09165	-1.43%
Off-Peak	0.01434	0.05324	0.06758	0.01734	0.05222	0.06956	2.94%
Customer Charge - $/month	275.69	0.00	275.69	291.00	0.00	291.00	5.55%
Facilities Related							
Demand Charge - $/kW	10.21	0.00	10.21	10.96	0.00	10.96	7.36%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.48	15.48	0.00	23.82	23.82	53.88%
Mid-Peak	0.00	5.24	5.24	0.00	6.68	6.68	27.48%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8 (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01289	0.07500	0.08789	0.01499	0.08456	0.09955	13.27%
Mid-peak	0.01289	0.05952	0.07241	0.01499	0.06754	0.08253	13.98%
Off-Peak	0.01289	0.03911	0.05200	0.01499	0.04695	0.06194	19.12%
Winter Season							
Mid-peak	0.01289	0.06123	0.07412	0.01499	0.06565	0.08064	8.80%
Off-Peak	0.01289	0.04137	0.05426	0.01499	0.04663	0.06162	13.57%
Customer Charge - $/month	2,427.22	0.00	2,427.22	2,232.25	0.00	2,232.25	-8.03%
Facilities Related							
Demand Charge - $/kW	2.80	0.00	2.80	4.47	0.00	4.47	59.78%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	12.22	12.22	0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21	0.00	5.35	5.35	27.08%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(0.95)	0.00	(0.95)	(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - $/kW							
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)	(0.15)	-66.67%
Energy - $/kWh	0.00000	(0.00087)	(0.00087)	0	(0.00066)	(0.00066)	24.14%
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2011 (100% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8 (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01481	0.09517	0.10998	0.01785	0.13015	0.14800	34.57%
Mid-peak	0.01481	0.07552	0.09033	0.01785	0.08550	0.10335	14.42%
Off-Peak	0.01481	0.04978	0.06459	0.01785	0.05739	0.07524	16.50%
Winter Season							
Mid-peak	0.01481	0.07750	0.09231	0.01785	0.07626	0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728	0.01785	0.05431	0.07216	7.26%
Customer Charge - $/month	458.04	0.00	458.04	542.25	0.00	542.25	18.38%
Facilities Related							
Demand Charge - $/kW	10.77	0.00	10.77	11.70	0.00	11.70	8.64%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.23	15.23	0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14	0.00	5.56	5.56	8.17%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8 (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01434	0.09652	0.11086	0.01734	0.09622	0.11356	2.44%
Mid-peak	0.01434	0.07662	0.09096	0.01734	0.07866	0.09600	5.55%
Off-Peak	0.01434	0.05049	0.06483	0.01734	0.05596	0.07330	13.07%
Winter Season							
Mid-peak	0.01434	0.07864	0.09298	0.01734	0.07431	0.09165	-1.43%
Off-Peak	0.01434	0.05324	0.06758	0.01734	0.05222	0.06956	2.94%
Customer Charge - $/month	275.69	0.00	275.69	291.00	0.00	291.00	5.55%
Facilities Related							
Demand Charge - $/kW	10.21	0.00	10.21	10.96	0.00	10.96	7.36%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.48	15.48	0.00	23.82	23.82	53.88%
Mid-Peak	0.00	5.24	5.24	0.00	6.68	6.68	27.48%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01289	0.07500	0.08789	0.01499	0.09021	0.10520	19.70%
Mid-peak	0.01289	0.05952	0.07241	0.01499	0.06975	0.08474	17.03%
Off-Peak	0.01289	0.03911	0.05200	0.01499	0.04695	0.06194	19.12%
Winter Season							
Mid-peak	0.01289	0.06123	0.07412	0.01499	0.06565	0.08064	8.80%
Off-Peak	0.01289	0.04137	0.05426	0.01499	0.04663	0.06162	13.57%
Customer Charge - $/month	2,427.22	0.00	2,427.22	2,232.25	0.00	2,232.25	-8.03%
Facilities Related							
Demand Charge - $/kW	2.80	0.00	2.80	4.47	0.00	4.47	59.78%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	12.22	12.22	0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21	0.00	5.35	5.35	27.08%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(0.95)	0.00	(0.95)	(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - $/kW							
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)	(0.15)	-66.67%
Energy - $/kWh	0.00000	(0.00087)	(0.00087)	0	(0.00066)	(0.00066)	24.14%
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2009 (50% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8-Backup (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01481	0.09517	0.10998	0.01785	0.12967	0.14752	34.14%
Mid-peak	0.01481	0.07552	0.09033	0.01785	0.08537	0.10322	14.28%
Off-Peak	0.01481	0.04978	0.06459	0.01785	0.05739	0.07524	16.50%
Winter Season							
Mid-peak	0.01481	0.07750	0.09231	0.01785	0.07626	0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728	0.01785	0.05431	0.07216	7.26%
Customer Charge - $/month	444.51	0.00	444.51	437.69	0.00	437.69	-1.53%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.23	15.23	0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14	0.00	5.56	5.56	8.17%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Backup (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01434	0.09652	0.11086	0.01734	0.09348	0.11082	-0.03%
Mid-peak	0.01434	0.07662	0.09096	0.01734	0.07794	0.09528	4.75%
Off-Peak	0.01434	0.05049	0.06483	0.01734	0.05596	0.07330	13.07%
Winter Season							
Mid-peak	0.01434	0.07864	0.09298	0.01734	0.07431	0.09165	-1.43%
Off-Peak	0.01434	0.05324	0.06758	0.01734	0.05222	0.06956	2.94%
Customer Charge - $/month	267.71	0.00	267.71	234.96	0.00	234.96	-12.23%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.48	15.48	0.00	23.82	23.82	53.88%
Mid-Peak	0.00	5.24	5.24	0.00	6.68	6.68	27.48%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8-Backup (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01289	0.07500	0.08789	0.01499	0.08456	0.09955	13.27%
Mid-peak	0.01289	0.05952	0.07241	0.01499	0.06754	0.08253	13.98%
Off-Peak	0.01289	0.03911	0.05200	0.01499	0.04695	0.06194	19.12%
Winter Season							
Mid-peak	0.01289	0.06123	0.07412	0.01499	0.06565	0.08064	8.80%
Off-Peak	0.01289	0.04137	0.05426	0.01499	0.04663	0.06162	13.57%
Customer Charge - $/month	2,355.83	0.00	2,355.83	1,801.69	0.00	1,801.69	-23.52%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	12.22	12.22	0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21	0.00	5.35	5.35	27.08%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(0.95)	0.00	(0.95)	(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - $/kW							
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)	(0.15)	-66.67%
Energy - $/kWh	0.00000	(0.00087)	(0.00087)	0	(0.00092)	(0.00092)	-5.75%

TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2011 (100% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)

	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Backup (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01481	0.09517	0.10998	0.01785	0.13015	0.14800	34.57%
Mid-peak	0.01481	0.07552	0.09033	0.01785	0.08550	0.10335	14.42%
Off-Peak	0.01481	0.04978	0.06459	0.01785	0.05739	0.07524	16.50%
Winter Season							
Mid-peak	0.01481	0.07750	0.09231	0.01785	0.07626	0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728	0.01785	0.05431	0.07216	7.26%
Customer Charge - $/month	444.51	0.00	444.51	437.69	0.00	437.69	-1.53%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.23	15.23	0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14	0.00	5.56	5.56	8.17%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8-Backup (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01434	0.09652	0.11086	0.01734	0.09622	0.11356	2.44%
Mid-peak	0.01434	0.07662	0.09096	0.01734	0.07866	0.09600	5.55%
Off-Peak	0.01434	0.05049	0.06483	0.01734	0.05596	0.07330	13.07%
Winter Season							
Mid-peak	0.01434	0.07864	0.09298	0.01734	0.07431	0.09165	-1.43%
Off-Peak	0.01434	0.05324	0.06758	0.01734	0.05222	0.06956	2.94%
Customer Charge - $/month	267.71	0.00	267.71	234.96	0.00	234.96	-12.23%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	15.48	15.48	0.00	23.82	23.82	53.88%
Mid-Peak	0.00	5.24	5.24	0.00	6.68	6.68	27.48%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8-Backup (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01289	0.07500	0.08789	0.01499	0.09021	0.10520	19.70%
Mid-peak	0.01289	0.05952	0.07241	0.01499	0.06975	0.08474	17.03%
Off-Peak	0.01289	0.03911	0.05200	0.01499	0.04695	0.06194	19.12%
Winter Season							
Mid-peak	0.01289	0.06123	0.07412	0.01499	0.06565	0.08064	8.80%
Off-Peak	0.01289	0.04137	0.05426	0.01499	0.04663	0.06162	13.57%
Customer Charge - $/month	2,355.83	0.00	2,355.83	1,801.69	0.00	1,801.69	-23.52%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	12.22	12.22	0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21	0.00	5.35	5.35	27.08%
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(0.95)	0.00	(0.95)	(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - $/kW							
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)	(0.15)	-66.67%
Energy - $/kWh	0.00000	(0.00087)	(0.00087)	0	(0.00092)	(0.00092)	-5.75%
STANDBY							
Capacity Reservation Charge - $/kW							
500 kW or less	6.37	0.00	6.37	5.14	0.00	5.14	-19.31%
Below 2 kV	6.37	0.00	6.37	5.14	0.00	5.14	-19.31%
From 2 kV to 50 kV	6.28	0.00	6.28	4.89	0.00	4.89	-22.13%
above 50, but < 220 kV	1.42	0.00	1.42	1.25	0.00	1.25	-11.97%
220 kV and above	0.16	0.00	0.16	0.65	0.00	0.65	306.25%

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
Backup Service							
Demand Charge - $/kW							
Summer Time-Related Demand Charges Effective 2009, phase-in at 50% of final (Paragraph 4.d.4)							
Summer Time Related Demand Charge - $/kW							
Below 2 kV							
On-Peak	0.00	11.63	11.63	0.00	16.16	16.16	38.96%
Mid-Peak	0.00	4.24	4.24	0.00	4.42	4.42	4.16%
From 2 kV to 50 kV							
On-Peak	0.00	11.87	11.87	0.00	18.63	18.63	56.91%
Mid-Peak	0.00	4.34	4.34	0.00	5.04	5.04	16.18%
Above 50, but < 220 kV							
On-Peak	0.00	8.61	8.61	0.00	16.03	16.03	86.15%
Mid-Peak	0.00	3.31	3.31	0.00	3.77	3.77	13.77%
220 kV and above							
On-Peak	0.00	8.45	8.45	0.00	15.86	15.86	87.74%
Mid-Peak	0.00	3.24	3.24	0.00	3.73	3.73	15.05%
Summer Time-Related Demand Charges Effective 2011 (Paragraph 4.d.3.a)							
Summer Time Related Demand Charge - $/kW							
Below 2 kV							
On-Peak	0.00	11.63	11.63	0.00	12.59	12.59	8.27%
Mid-Peak	0.00	4.24	4.24	0.00	3.27	3.27	-22.82%
From 2 kV to 50 kV							
On-Peak	0.00	11.87	11.87	0.00	13.43	13.43	13.15%
Mid-Peak	0.00	4.34	4.34	0.00	3.40	3.40	-21.55%
Above 50, but < 220 kV							
On-Peak	0.00	8.61	8.61	0.00	11.79	11.79	36.99%
Mid-Peak	0.00	3.31	3.31	0.00	2.18	2.18	-34.08%
220 kV and above							
On-Peak	0.00	8.45	8.45	0.00	11.67	11.67	38.16%
Mid-Peak	0.00	3.24	3.24	0.00	2.16	2.16	-33.35%
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2009 (50% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8 (Below 2kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01785	0.31808	0.33593	
Mid-peak				0.01785	0.12658	0.14443	
Off-Peak				0.01785	0.05739	0.07524	
Winter Season							
Mid-peak				0.01785	0.07626	0.09411	
Off-Peak				0.01785	0.05431	0.07216	
Customer Charge - $/month				542.25	0.00	542.25	
Facilities Related							
Demand Charge - $/kW				11.70	0.00	11.70	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27	0.00	0.27	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (From 2 kV to 50 kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01734	0.32057	0.33791	
Mid-peak				0.01734	0.12560	0.14294	
Off-Peak				0.01734	0.05596	0.07330	
Winter Season							
Mid-peak				0.01734	0.07431	0.09165	
Off-Peak				0.01734	0.05222	0.06956	
Customer Charge - $/month				291.00	0.00	291.00	
Facilities Related							
Demand Charge - $/kW				10.96	0.00	10.96	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27	0.00	0.27	
TOU-8 (Above 50 kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01499	0.26826	0.28325	
Mid-peak				0.01499	0.10321	0.11820	
Off-Peak				0.01499	0.04695	0.06194	
Winter Season							
Mid-peak				0.01499	0.06565	0.08064	
Off-Peak				0.01499	0.04662	0.06161	
Customer Charge - $/month				2232.25	0.00	2232.25	
Facilities Related							
Demand Charge - $/kW				4.47	0.00	4.47	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.32	0.00	0.32	
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2011 (100% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8 (Below 2kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01785	0.31856	0.33641	
Mid-peak				0.01785	0.12672	0.14457	
Off-Peak				0.01785	0.05739	0.07524	
Winter Season							
Mid-peak				0.01785	0.07626	0.09411	
Off-Peak				0.01785	0.05431	0.07216	
Customer Charge - $/month				542.25	0.00	542.25	
Facilities Related							
Demand Charge - $/kW				11.70	0.00	11.70	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27	0.00	0.27	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (From 2 kV to 50 kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01734	0.32331	0.34065	
Mid-peak				0.01734	0.12632	0.14366	
Off-Peak				0.01734	0.05596	0.07330	
Winter Season							
Mid-peak				0.01734	0.07431	0.09165	
Off-Peak				0.01734	0.05222	0.06956	
Customer Charge - $/month				291.00	0.00	291.00	
Facilities Related							
Demand Charge - $/kW				10.96	0.00	10.96	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27	0.00	0.27	
TOU-8 (Above 50 kV) - Option A							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01499	0.27391	0.28890	
Mid-peak				0.01499	0.10542	0.12041	
Off-Peak				0.01499	0.04695	0.06194	
Winter Season							
Mid-peak				0.01499	0.06565	0.08064	
Off-Peak				0.01499	0.04662	0.06161	
Customer Charge - $/month				2232.25	0.00	2232.25	
Facilities Related							
Demand Charge - $/kW				4.47	0.00	4.47	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.32	0.00	0.32	
Optional CPP rider < 200 kW							
CPP Event Energy Charge - $/kWh							
GS-2				0.00000	1.36229	1.36229	
GS-2-TOU				0.00000	1.36229	1.36229	
Summer Non-Event Demand Credit - $/kWh							
GS-2				0.00	(10.19)	(10.19)	
GS-2-TOU (On-Peak Dmand)				0.00	(9.39)	(9.39)	
Default CPP rider > 200 kW							
TOU-GS-3							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - $/kW				0.00000	(11.62)	(11.62)	
TOU-8-SEC							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - $/kW				0.00000	(12.47)	(12.47)	
TOU-8-PRI							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.33322	1.33322	
Summer On Peak Demand Credit - $/kW				0.00000	(12.20)	(12.20)	
TOU-8-SUB							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.28157	1.28157	
Summer On Peak Demand Credit - $/kW				0.00000	(13.02)	(13.02)	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-2 (TOU Option R)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.03950	0.34112	0.38062	
Mid-peak				0.03950	0.13287	0.17237	
Off-Peak				0.03950	0.05486	0.09436	
Winter Season							
Mid-peak				0.03950	0.07751	0.11701	
Off-Peak				0.03950	0.05195	0.09145	
Customer Charge - $/month				114.25		114.25	
Facilities Related Demand Charge - $/kW				5.81		5.81	
Single Phase Service - $/month				(9.94)		(9.94)	
TOU-GS-3 (Option R)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.03596	0.25634	0.29230	
Mid-peak				0.03596	0.12074	0.15670	
Off-Peak				0.03596	0.06493	0.10089	
Winter Season							
Mid-peak				0.03596	0.06921	0.10517	
Off-Peak				0.03596	0.05402	0.08998	
Customer Charge - $/month				443.75		443.75	
Facilities Related							
Demand Charge - $/kW				6.23		6.23	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak						0.00	
Mid-Peak						0.00	
Winter Season							
Mid-Peak							
Off-Peak							
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV							
above 50 kV							
<u>TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2009 (50% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)</u>							
TOU-8 (Below 2kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.03174	0.31808	0.34982	
Mid-peak				0.03174	0.12658	0.15832	
Off-Peak				0.03174	0.05739	0.08913	
Winter Season							
Mid-peak				0.03174	0.07626	0.10800	
Off-Peak				0.03174	0.05431	0.08605	
Customer Charge - $/month				542.25		542.25	
Facilities Related							
Demand Charge - $/kW				5.85		5.85	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27		0.27	
TOU-8 (From 2 kV to 50 kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.02937	0.32057	0.34994	
Mid-peak				0.02937	0.12560	0.15497	
Off-Peak				0.02937	0.05596	0.08533	
Winter Season							
Mid-peak				0.02937	0.07431	0.10368	
Off-Peak				0.02937	0.05222	0.08159	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

	Rates Effective December 2008			Settlement Rates			
Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
Customer Charge - $/month				291.00		291.00	
Facilities Related							
Demand Charge - $/kW				5.48		5.48	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27		0.27	
TOU-8 (Above 50 kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01692	0.26826	0.28518	
Mid-peak				0.01692	0.10321	0.12013	
Off-Peak				0.01692	0.04695	0.06387	
Winter Season							
Mid-peak				0.01692	0.06565	0.08257	
Off-Peak				0.01692	0.04662	0.06354	
Customer Charge - $/month				2232.25		2232.25	
Facilities Related							
Demand Charge - $/kW				3.48		3.48	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.32		0.32	
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2011 (100% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4)							
TOU-8 (Below 2kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.03174	0.31856	0.35030	
Mid-peak				0.03174	0.12672	0.15846	
Off-Peak				0.03174	0.05739	0.08913	
Winter Season							
Mid-peak				0.03174	0.07626	0.10800	
Off-Peak				0.03174	0.05431	0.08605	
Customer Charge - $/month				542.25		542.25	
Facilities Related							
Demand Charge - $/kW				5.85		5.85	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27		0.27	
TOU-8 (From 2 kV to 50 kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.02937	0.32331	0.35268	
Mid-peak				0.02937	0.12632	0.15569	
Off-Peak				0.02937	0.05596	0.08533	
Winter Season							
Mid-peak				0.02937	0.07431	0.10368	
Off-Peak				0.02937	0.05222	0.08159	

Medium and Large Power Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Generation	Total Rate	Settlement Rates Delivery	Generation	Total Rate	Total Rate Change
Customer Charge - $/month				291.00		291.00	
Facilities Related							
Demand Charge - $/kW				5.48		5.48	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.27		0.27	
TOU-8 (Above 50 kV) - Option R							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.01692	0.27391	0.29083	
Mid-peak				0.01692	0.10542	0.12234	
Off-Peak				0.01692	0.04695	0.06387	
Winter Season							
Mid-peak				0.01692	0.06565	0.08257	
Off-Peak				0.01692	0.04662	0.06354	
Customer Charge - $/month				2232.25		2232.25	
Facilities Related							
Demand Charge - $/kW				3.48		3.48	
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA				0.32		0.32	

(END OF ATTACHMENT D)

ATTACHMENT E

Agriculture and Pumping Rate Group Rate Design 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, And Design Rates	))))	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	))))	Application 07-12-020 (Filed December 21, 2007)

PHASE 2 AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Dated: February 4, 2009

AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

PHASE 2 AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Agriculture And Pumping Rate Group Rate Design Settlement 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), California Farm Bureau Federation (CFBF), and Agricultural Energy Consumers Association (AECA), (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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. CFBF is a voluntary, private, non-profit corporation representing more than 85,000 members and over 80 percent of California's commercial agriculture.

c. 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.

2. Recitals

a. In Phase 2 of SCE’s 2009 General Rate Case, the Commission allocates SCE’s authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008.

c. In accordance with the Scoping Memo and Ruling of the Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners, including the Settling Parties, served their initial testimony on October 31, 2008.

e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Agriculture and Pumping rate group as indicated in Paragraph 4 of this Agreement.

3. Definitions

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Account Aggregation" refers to virtual aggregation of a single customer's multiple service accounts for generation billing purposes. Under this method of aggregation, each of the aggregated accounts is separately metered; however, the generation time-related billing demands would be aggregated at the billing system level to reflect some level of diversity. All other billing determinants are treated consistent with separately-metered accounts.

b. “Agreement” shall have the meaning given to such term in the introductory paragraph hereof.

c. “Agriculture and Pumping Rate Groups” refers to customers with demands less than 500 kW who receive service on the following SCE rate schedules: PA-1, PA-2, TOU-PA, TOU-PA-5, TOU-PA-SOP, and PA-RTP.

d. “BIP”, “API-BIP”, or Base Interruptible Program means a rate schedule applicable to time-of-use agriculture and pumping customers who receive a credit applied to their summer and winter Time-Related Demand Charges in return for the customer’s agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.

e. “Commission” or “CPUC” means the California Public Utilities Commission.

f. “Critical Peak Pricing” or CPP means a dynamic rate that allows a short-term price increase to a predetermined level to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the event days are not predetermined.

g. “Customer Charges” mean the dollar per month charges applicable to certain Agriculture and Pumping Rate Group rate schedules.

h. “Demand Charges” mean those charges that are comprised of Facilities-Related Demand Charges and Time-Related Demand Charges, which are based on the customer’s maximum kW demand during the billing period. Demand Charges recover a portion of SCE’s delivery and generation costs.

i. “Energy Charges” mean the dollar per kilowatt-hour (kWh) charges applicable to rate schedules in the Agriculture and Pumping rate group.

Energy Charges recover a portion of SCE's costs for delivery service and generation. For TOU rate schedules, utility retained generation Energy Charges are set residually such that the weighted average of URG and DWR Energy Charges provides a TOU price signal consistent with marginal cost differentials.

j. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.* separately for generation versus distribution, and customer).

k. "Facilities-Related Demand Charges" are charges applied to customers' monthly peak demands not differentiated by TOU or by season that are designed to recover certain transmission and distribution costs that are defined to be unrelated to generation system peak or coincident peak usage.

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

m. "Settling Parties" means SCE, CFBF, and AECA.

n. "Time-Related Demand Charges" are generation-related, marginal cost based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities or loss of load expectations during the TOU periods. Scaled TOU marginal energy costs along with the Time-Related Demand Charges are designed to collect the allocated revenue requirement for SCE's base generation and fuel and purchased power costs.

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 Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. Common Pricing Principles

1. **Rate Structure**

   The current rate structure, consisting of Customer Charges, Energy Charges, and Demand Charges shall be maintained for all applicable rate schedules, with the exception of Schedule PA-2 which will now include a summer Time-Related Demand Charge.

2. **Customer Charges**

   Effective October 1, 2009, Customer Charges shall be increased by a maximum of 20 percent above current levels, but in no case shall the charges exceed the full EPMC level of Customer Charge based on SCE's RECC method. Any revenue deficiencies caused by the capping will be recovered in distribution energy charges.

3. **Demand Charges**

   Demand Charges shall be differentiated by season. However, the seasonality, and in some cases time differentiation, shall be retained in the design of Time-Related Demand Charges only, with no seasonal or TOU differences in the Facilities-Related Demand Charges.

4. **Non-Generation Related Energy Charges**

   Energy Charges that are designed to recover revenues associated with transmission, distribution, public purpose programs, nuclear decommissioning, CARE balancing account, PUCRF and the California Department of Water Resources bonds shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Agreement, which was filed January 9, 2009.

5. **Demand Response Credits**

   Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, AP-I, API-BIP, and CPP shall be as proposed by SCE in Exhibit SCE-04 (Updated), dated June 27, 2008.

6. **Implementing Revenue Changes in Rates**

   Changes to Energy Charges and Demand Charges shall be implemented on a Functional SAPC allocation basis whenever changes to SCE's authorized distribution and generation revenue requirements are implemented.

7. **Illustrative Rates**

   Rates for the Agriculture and Pumping Rate Group shall be designed consistent with Appendix A.

b. Agriculture and Pumping Rate Groups

1. **Schedules PA-1 and PA-2**

   Customers with peak demands up to 199 kW shall take service on a default basis on an applicable non-TOU rate schedule (Schedule PA-1 or PA-2). Customers shall also have the option of taking service on an applicable TOU rate schedule, *e.g.* Schedule TOU-

PA. For Schedule PA-1, the default rate structure shall consist of a monthly Customer Charge, a Service Charge, and Energy Charge. For Schedule PA-2, the default rate structure shall consist of a monthly Customer Charge, a seasonal Time-Related Demand Charge, a Facilities-Related Demand Charge, and seasonal Energy Charges. Customers served on rate schedules in these rate groups shall have the option, unless they are otherwise ineligible, to participate on the CPP tariff.

2. TOU-PA and TOU-PA-5 Rate Groups

Schedule TOU-PA (Rate B) is the default rate schedule with Schedules TOU-PA (Rate A) and TOU-PA-5 as optional rate schedules for agriculture and pumping customers with demands greater than 200 kW. The default rate structure shall consist of a monthly Customer Charge, seasonal Time-Related Demand Charges, a Facilities-Related Demand Charge, and seasonal Energy Charges. Customers served on rate schedules in these rate groups shall have the option, unless they are otherwise ineligible, to participate on the CPP tariff.

3. Schedule TOU-PA-SOP and PA-RTP Options

The optional super off-peak (SOP) and real-time pricing (RTP) schedules shall remain available for customers who meet the applicability criteria. Schedule TOU-PA-SOP shall retain its existing rate and TOU period structure. The total SOP energy rate will be set initially at current levels; however, the rate will be adjusted based on the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Settlement Agreement. Schedule PA-RTP will remain open to new customers and will be designed to be revenue neutral to Schedule TOU-PA (Rate B). The real-time energy prices for PA-RTP shall be established using the same methodology as used for RTP-2 described in Exhibit SCE-04 (Updated), dated June 27, 2008 consistent with the following: Schedule PA-RTP generation capacity charges shall reflect a generation marginal capacity cost of $114.10 per kW per year. Schedule PA-RTP Energy Charges shall reflect a generation marginal energy cost based on a natural gas burnertip price of $7.00 per million BTUs. Delivery service rates for Schedule PA-RTP shall be the same as the delivery service rates for Schedule TOU-PA (Rate B). The applicability for Schedule PA-RTP shall be modified to be consistent with Schedule TOU-PA (Rate B).

4. **Schedule TOU-PA-7**

Schedule TOU-PA-7 shall be eliminated. Customers currently served on this schedule will be transferred to their otherwise applicable tariff, or any available optional tariff of their choosing.

c. **Customer Charges**

Effective October 1, 2009, estimated monthly Customer Charges shall be as follows:

Agriculture and Pumping Rate Groups
Estimated Customer Charges ($/mo.)

Rate Schedule	Customer Charge
PA-1	36.02
PA-2	70.69
TOU-PA	100.48
TOU-PA-5	102.07
TOU-PA-SOP	100.48

d. **Time-Related Demand Charges**

Time-Related Demand Charges shall be established consistent with the values for generation marginal energy and capacity costs, relative loss-of-load expectation and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement.

The Time-Related Demand Charges for Schedules TOU-PA (Rate B) and TOU-PA-5 shall be established in the same manner as for TOU-GS-3 and TOU-8-Sec rate groups*, i.e.* with an assumed generation marginal capacity cost of $95 per kW per year, instead of the $114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The generation revenue deficiency caused by this adjusted generation marginal capacity cost shall be recovered solely in the summer season on-peak and mid-peak Energy Charges for Schedule TOU-PA (Rate B) and Schedule TOU-PA-5,

The Schedule PA-2 summer season Time-Related Demand Charge shall be capped at $3.50 per kW. The generation revenue deficiency caused by this cap shall be recovered solely in the summer season Energy Charge for the PA-2 rate group.

Agriculture and Pumping Rate Group
Estimated Time-Related Demand Charges
($/kW)

	TOU-PA Rate B	TOU-PA-5	TOU-PA-SOP
Summer On-Peak	11.22	15.01	25.75
Summer Mid-Peak	2.68	4.21	0.0

On October 1, 2009, these estimated Time-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Time-Related Demand Charges shall be adjusted by the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

e. Facilities-Related Demand Charges

Estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission revenues) for the Agriculture and Pumping rate groups shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design (Exhibit SCE-04 (Updated)) as follows:

Agriculture and Pumping Rate Group
Estimated Facilities-Related Demand Charges
($/kW)

PA-2	TOU-PA	TOU-PA-5	TOU-PA-SOP
7.71	7.22	10.23	7.22

On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

f. Energy Charges

Generation-related Energy Charges shall be established based on marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to each Agriculture and Pumping Rate Group. As described in paragraph 4.d., above, any revenue deficiency resulting from the capped SCE generation capacity charges reflected in the TOU-PA (Rate B), TOU-PA-5, and PA-2 rate schedules will be recovered through the respective TOU or seasonal energy charges for these rate schedules. For Schedule TOU-PA (Rate A), the total summer on-peak energy rate shall be capped initially at 20 cents per kWh, and the resulting revenue deficiency will be recovered through the winter mid-peak energy charge. For PA-SOP, the winter and summer total super off peak energy rates shall be set initially at current levels. The resulting summer revenue deficiency will be recovered through the applicable summer on-peak energy rate, and the resulting winter revenue deficiency will be recovered through the winter mid-peak energy rate.

g. CPP Program Design and Revenue Treatment

1. CPP Design

CPP will be optional for the Agriculture and Pumping rate group. SCE's CPP tariff shall allow no more than 15 events per year, nor less than 9 events per year, but is designed to be activated for 12 events per year on non-holiday summer weekdays and may occur only during the time period from 2:00 p.m. to 6:00 p.m.

2. CPP Bill Protection

A customer who is subject to the CPP tariff (regardless of demand level) shall be provided bill protection such that bills under CPP for the first 12 months shall not exceed bills calculated on the customer's otherwise applicable tariff provided the customer remains on the CPP tariff for a full year. Customers who do not remain on the CPP tariff for a full year shall forfeit any bill protection credits.

3. CPP Revenue Allocation

An undercollection of revenues relative to the design of the CPP rate will occur when fewer than the number of design events are called, and an overcollection will occur when the number of called events is greater than the number of designed events. The revenue imbalances resulting in the ERRA balancing account from this variation shall be retained in the rate group that is responsible for the amount of the revenue imbalance.

h. Schedule PA-2 Customers

As described in sections 4.a.2. and 4.d., above, the rate structure for

Schedule PA-2 will be modified to include a summer season demand charge. The Settling Parties agree that customers who are potentially impacted should be made aware of this change. Accordingly, by the end of calendar year 2009, SCE will perform a one-time review of PA-2 customers' annual bills. Where bill comparisons indicate that customers may achieve significant annual percentage bill savings on Schedule PA-1, *e.g.,* three percent or more, SCE will notify such customers and offer them the opportunity to change to Schedule PA-1.

i. TOU-PA Customers

By the end of calendar year 2009, SCE will perform a one-time review of TOU-PA-B, TOU-PA-5 and TOU-PA-SOP customers' annual bills. Where bill comparisons indicate that customers may achieve significant annual percentage bill savings on other rate schedules, *e.g.,* three percent or more, SCE will notify such customers and offer them the opportunity to change to the alternative rate schedule.

j. Customer Account Aggregation

Aggregation of customer accounts, as proposed by AECA in this proceeding, will not be permitted. In lieu of Account Aggregation, SCE will offer customers an hourly pricing schedule similar to the current PA-RTP schedule. In addition, SCE agrees to work with AECA and other interested parties to identify energy cost management tools and technologies for agricultural customers.

k. Review of Revenue Allocation and Rate Design Issues

SCE agrees to meet with representatives of AECA and CFBF to review the issues on revenue allocation and rate design raised by each party in its prepared testimony. The intention of this meeting is to (1) resolve factual and analytical issues where possible and (2) discuss potential joint studies that might assist in resolving issues prior to SCE's filing of its next general rate case application.

5. Implementation of Agreement

It is the intent of the 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 October 1, 2009.

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 Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

7. Signature Date

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

8. Regulatory Approval

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

9. Compromise Of Disputed Claims

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

10. 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.

11. Previous Communications

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties.

12. 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.

13. Effect Of Subject Headings

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

14. 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.

15. <u>Number Of Originals</u>

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 Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce Reed

Title: Senior Attorney Date: 2/5/2009

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ron Liebert

Title: Associate Counsel Date: 2/5/2009

AGRICULTURAL ENERGY USERS ASSOCIATION

By: /s/ Dan Geis

Title: Assistant Executive Director Date: 2/5/2009

Appendix A

Agriculture and Pumping Rate Groups Illustrative Rates

Agriculture and Pumping Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.

	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
PA-1							
Energy Charge - $/kWh	0.02559	0.10973	0.13532	0.04313	0.11012	0.15325	13.25%
Customer Charge - $/month	30.02	0.00	30.02	36.02	0.00	36.02	19.99%
Service Charge - $/hp	2.23	0.00	2.23	2.05	0.00	2.05	-7.85%
Off Peak Credit - $/hp	(2.01)	0.00	(2.01)	0.00	(2.03)	(2.03)	-1.00%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00210)	(0.00210)	-5.59%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00468)	(0.00468)	-8.05%
Voltage Discount, Connected Load - $/Hp							
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.03)	0.00	(0.03)	78.57%
above 50 kV	(4.66)	0.00	(4.66)	(0.95)	0.00	(0.95)	79.61%
PA-2							
Energy Charge - $/kWh							
Summer	0.01551	0.07351	0.08902	0.01886	0.11196	0.13082	46.96%
Winter	0.01551	0.07171	0.08722	0.01886	0.06671	0.08557	-1.89%
Customer Charge - $/month	58.91	0.00	58.91	70.69	0.00	70.69	20.00%
Facilities Related							
Demand Charge - $/kW	8.83	0.00	8.83	7.71	0.00	7.71	-12.64%
Time Related Demand Charge - $/kW							
Summer Season	0.00	0.00	0.00	0.00	3.50	3.50	
Winter Season	0.00	0.00	0.00	0.00	0.00	0.00	
~~TOU Option Meter Charge - $/month~~							
~~Standard~~	~~18.43~~	~~0.00~~	~~18.43~~	~~21.23~~	~~0.00~~	~~21.23~~	~~15.19%~~
TOU-RTEM	158.83	0.00	158.83	88.48	0.00	88.48	-44.29%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.09)	0.00	(0.09)	52.63%
above 50 kV	(6.25)	0.00	(6.25)	(2.98)	0.00	(2.98)	52.32%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	0.00	0.00	0.00	(0.35)	(0.35)	
above 50 kV	0.00	0.00	0.00	0.00	(0.96)	(0.96)	
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00140)	(0.00140)	29.61%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00312)	(0.00312)	27.97%
PA-RTP							
Energy Charge - $/kWh	0.01356		Variable*	0.01662	Variable*	Variable*	
Customer Charge - $/month	83.73	0.00	83.73	100.48	0.00	100.48	20.00%
Facilities Related							
Demand Charge - $/kW	4.46	0.00	4.46	7.22	0.00	7.22	61.82%
Voltage Discount, Hourly Rates - %							
From 2 kV to 50 kV	0.00%			0.00%	-2.39%	-2.39%	
above 50 kV	0.00%			0.00%	-5.32%	-5.32%	
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%

***See RTP Schedules for PA-RTP.**

Agriculture and Pumping Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-PA (Rate A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01356	0.10204	0.11560	0.01662	0.18338	0.20000	73.01%
Mid-peak	0.01356	0.08615	0.09971	0.01662	0.09155	0.10817	8.49%
Off-Peak	0.01356	0.03509	0.04865	0.01662	0.04769	0.06431	32.19%
Winter Season							
Mid-peak	0.01356	0.09745	0.11101	0.01662	0.08467	0.10129	-8.75%
Off-Peak	0.01356	0.03509	0.04865	0.01662	0.04611	0.06273	28.95%
Customer Charge - $/month	83.73	0.00	83.73	100.48	0.00	100.48	20.00%
Service Charge - $/hp	3.75	1.03	4.78	5.41	0.00	5.41	13.21%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00432)	(0.00432)	0.00000	(0.00294)	(0.00294)	31.92%
Voltage Discount, Connected Load - $/Hp							
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.07)	0.00	(0.07)	50.00%
above 50 kV	(4.68)	0.00	(4.68)	(2.28)	0.00	(2.28)	51.28%
TOU-PA (Rate B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01356	0.09989	0.11345	0.01662	0.10324	0.11986	5.65%
Mid-peak	0.01356	0.08224	0.09580	0.01662	0.06729	0.08391	-12.41%
Off-Peak	0.01356	0.03510	0.04866	0.01662	0.04770	0.06432	32.19%
Winter Season							
Mid-peak	0.01356	0.09320	0.10676	0.01662	0.06686	0.08348	-21.80%
Off-Peak	0.01356	0.03510	0.04866	0.01662	0.04613	0.06275	28.96%
Customer Charge - $/month	83.73	0.00	83.73	100.48	0.00	100.48	20.00%
Facilities Related							
Demand Charge - $/kW	5.01	0.00	5.01	7.22	0.00	7.22	44.05%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	9.77	9.77	0.00	11.22	11.22	14.84%
Mid-Peak	0.00	0.00	0.00	0.00	2.68	2.68	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.10)	0.00	(0.10)	47.37%
above 50 kV	(6.25)	0.00	(6.25)	(3.04)	0.00	(3.04)	51.36%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.19)	(0.19)	51.28%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(0.54)	(0.54)	48.08%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00432)	(0.00432)	0.00000	(0.00294)	(0.00294)	31.92%
TOU-PA (Both Options)							
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%

Agriculture and Pumping Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-PA-5							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01362	0.06646	0.08008	0.01641	0.09954	0.11595	44.79%
Mid-peak	0.01362	0.05368	0.06730	0.01641	0.06785	0.08426	25.20%
Off-Peak	0.01362	0.03173	0.04535	0.01641	0.04398	0.06039	33.16%
Winter Season							
Mid-peak	0.01362	0.05666	0.07028	0.01641	0.05912	0.07553	7.47%
Off-Peak	0.01362	0.03352	0.04714	0.01641	0.04171	0.05812	23.29%
Customer Charge - $/month	85.06	0.00	85.06	102.07	0.00	102.07	20.00%
Minimum Charge - $/kW							
Summer Season	9.94	29.46	39.40	10.69	29.46	40.15	1.90%
Winter Season	8.42	11.99	20.41	9.19	11.99	21.18	3.75%
Facilities Related							
Demand Charge - $/kW	9.95	0.00	9.95	10.23	0.00	10.23	2.80%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	10.49	10.49	0.00	15.01	15.01	43.09%
Mid-Peak	0.00	0.00	0.00	0.00	4.21	4.21	
Winter Season							
Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.14)	0.00	(0.14)	26.32%
above 50 kV	(6.24)	0.00	(6.24)	(4.50)	0.00	(4.50)	27.88%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.31)	(0.31)	20.51%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(0.86)	(0.86)	17.31%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0	(0.00134)	(0.00134)	32.54%
above 50 kV	0.00000	(0.00432)	(0.00432)	0	(0.00299)	(0.00299)	30.81%
TOU-PA-ICE							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01885	0.13670	0.15555	0.02207	0.13581	0.15788	1.50%
Mid-peak	0.01885	0.07425	0.09310	0.02207	0.07242	0.09449	1.49%
Off-Peak	0.01885	0.02293	0.04178	0.02207	0.02033	0.04240	1.48%
Winter Season							
Mid-peak	0.01885	0.09385	0.11270	0.02207	0.09231	0.11438	1.49%
Off-Peak	0.01885	0.02293	0.04178	0.02207	0.02033	0.04240	1.48%
Customer Charge - $/month	50.14	0.00	50.14	50.89	0.00	50.89	1.50%
Facilities Related							
Demand Charge - $/kW	3.02	0.00	3.02	3.07	0.00	3.07	1.66%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	1.09	0.05	1.14	1.09	0.07	1.16	1.75%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.10)	0.00	(0.10)	(0.10)	0.00	(0.10)	0.00%
above 50 kV	(2.39)	0.00	(2.39)	(2.39)	0.00	(2.39)	0.00%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.18)	0.00	(0.18)	0.00%
above 50 kV	(1.09)	0.00	(1.09)	(1.09)	0.00	(1.09)	0.00%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00049)	(0.00049)	0.00000	(0.00068)	(0.00068)	-38.78%
above 50 kV	0.00000	(0.00105)	(0.00105)	0.00000	(0.00145)	(0.00145)	-38.10%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.00	0.00	0.00	-100.00%
50 kV or less	0.18	0.00	0.18	0.00	0.00	0.00	-100.00%

Agriculture and Pumping Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008			Settlement Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-PA-SOP							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.01356	0.08150	0.09506	0.01662	0.09592	0.11254	18.39%
Off-peak	0.01356	0.05672	0.07028	0.01662	0.05786	0.07448	5.98%
Super Off-Peak	0.01356	0.03404	0.04760	0.01662	0.03098	0.04760	0.01%
Winter Season							
Off-peak	0.01356	0.05689	0.07045	0.01662	0.06748	0.08410	19.38%
Super Off-Peak	0.01356	0.03368	0.04724	0.01662	0.03061	0.04723	-0.02%
Customer Charge - $/month	83.73	0.00	83.73	100.48	0.00	100.48	20.00%
Facilities Related							
Demand Charge - $/kW	5.01	0.00	5.01	7.22	0.00	7.22	44.05%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	18.56	18.56	0.00	25.75	25.75	38.74%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Winter Season							
Off-Peak	0.00			0.00	0.00	0.00	
Super Off-Peak	0.00			0.00	0.00	0.00	
Other Charges							
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.10)	0.00	(0.10)	47.37%
above 50 kV	(6.25)	0.00	(6.25)	(3.04)	0.00	(3.04)	51.36%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.19)	(0.19)	51.28%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(0.54)	(0.54)	48.08%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00432)	(0.00432)	0.00000	(0.00294)	(0.00294)	31.92%
AP-I							
Interruptible Credit							
$/kWh	(0.00933)	0.00000	(0.00933)	(0.01164)	0.00000	(0.01164)	-24.76%
Excess Energy Charge - $/kWh				12.21107	0.00000	12.21107	
~~Below 2 kV~~	~~10.21374~~	~~0.00000~~	~~10.21374~~	~~0.53693~~	~~0.00000~~	~~0.53693~~	~~-94.74%~~
~~From 2 kV to 50 kV~~	~~9.99551~~	~~0.00000~~	~~9.99551~~	~~0.53693~~	~~0.00000~~	~~0.53693~~	~~-94.63%~~
~~above 50 kV~~	~~9.63234~~	~~0.00000~~	~~9.63234~~	~~0.53693~~	~~0.00000~~	~~0.53693~~	~~-94.43%~~
AGTOU-BIP							
BIP Option Credit ($/KW)							
Summer On Peak				(17.22)	0.00	(17.22)	
Summer Mid - Peak				(3.66)	0.00	(3.66)	
Winter Mid - Peak				(1.25)	0.00	(1.25)	
Excess Energy Charge - $/kWh				12.21107	0.00000	12.21107	

Agriculture and Pumping Rate Groups -- Current and Settlement Rate Design

Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Rates Effective December 2008 Delivery	Rates Effective December 2008 Generation	Rates Effective December 2008 Total Rate	Settlement Rates Delivery	Settlement Rates Generation	Settlement Rates Total Rate	Total Rate Change
Optional CPP rider < 200 kW							
CPP Event Energy Charge - $/kWh							
PA-1				0.00000	1.36229	1.36229	
PA-2				0.00000	1.36229	1.36229	
AG-TOU				0.00000	1.36229	1.36229	
TOU-PA-5				0.00000	1.36229	1.36229	
Summer Non-Event Energy Credit - $/kWh							
PA-1				0.00000	-0.02752	-0.02752	
Summer Non-Event Demand Credit - $/kWh							
PA-2				0.00	(7.44)	(7.44)	
AG-TOU				0.00	(8.69)	(8.69)	
TOU-PA-5				0.00	(12.39)	(12.39)	
Default CPP rider > 200 kW							
AG-TOU							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - $/kW				0.00000	(8.69)	(8.69)	
TOU-PA-5							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh				0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - $/kW				0.00000	(12.39)	(12.39)	

(END OF ATTACHMENT E)

ATTACHMENT F

Street Light Rate Group 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, And Design Rates	))))	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	))))	Application 07-12-020 (Filed December 21, 2007)

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2 STREET LIGHT RATE GROUP SETTLEMENT AGREEMENT

Dated: January 5, 2009

#1591782-v11

Phase 2
Street Light Rate Group Settlement Agreement

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2
STREET LIGHT RATE GROUP SETTLEMENT AGREEMENT

This Phase 2 Street Light Rate Group Settlement 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), California City-County Street Light Association (CAL-SLA), and Pleasant Valley Recreation and Park District (PVRPD) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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. CAL-SLA represents cities and counties that take street and area lighting and traffic signal services from SCE and the other two major investor-owned utilities, Pacific Gas & Electric Company and San Diego Gas & Electric Company.

c. PVRPD is a recreation and park district, which was formed in 1962 under the California Public Resources Code. PVRPD owns and operates 27 public parks in or around Camarillo, California. Electricity service to these parks consists primarily of outdoor lighting and is provided by SCE. The outdoor lighting accounts are characterized by relatively high maximum demand and low load factors and are currently served on SCE's Schedule GS-2 because the accounts have some incidental load that cannot be limited to the dusk to dawn requirement of Schedule AL-2.

2. Recitals

a. In Phase 2 of SCE's 2009 General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners, including CAL-SLA and PVRPD served their initial testimony on October 31, 2008.

e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Street Light Rate Group as indicated in Paragraph 4 of this Agreement.

3. Definitions

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

b. "Settling Parties" means SCE, CAL-SLA, and PVRPD.

c. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to street and area lighting rate schedules. Energy Charges recover SCE's costs for delivery service and generation.

d. "Customer Charges" mean the dollar per month charges applicable to certain Street Light Rate Group and traffic control rate schedules.

e. "Non-Energy Charges" mean the distribution charges applicable to street and area lighting facilities owned and maintained by SCE. Non-Energy Charges are expressed as dollars per lamp per month. Non-Energy Charges are synonymous with "facilities charges", "service charges", and "other charges" applicable to street and area lighting.

f. "Street Light Rate Group" means the following SCE rate schedules: Schedule LS-1 Lighting – Street and Highway Company-Owned System, Schedule LS-2 Lighting – Street and Highway Customer-Owned Installation – Unmetered Service, Schedule LS-3, Lighting – Street and Highway Customer-Owned Installation – Metered Service, Schedule OL-1 Outdoor Area Lighting Service, Schedule DWL Residential Walkway Lighting, and Schedule AL-2 Outdoor Area Lighting Service Metered.

g. "Target Lamp Charges" mean Non-Energy Charges that shall be established as provided in Paragraph 4.c of this Agreement for the period from October 1, 2009 through rate changes implemented as a result of Phase 2 of SCE's 2012 general rate case (GRC).

h. "Allocated Revenues" mean the amount of SCE's revenue requirement allocated to the Street Light Rate Group. Allocated Revenues are used to establish the Energy Charges applicable to the Street Light Rate Group.

i. "Non-Allocated Revenues" mean the revenues collected from Non-Energy Charges. These costs are assigned directly to the Street Light Rate Group and are excluded from SCE's allocation of the revenue requirement to all rate groups. Non-Allocated Revenues for 2009, 2010, 2011, and 2012 shall be based on Non-Energy Charges calculated according to Paragraph 4 in this Agreement.

j. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change for the particular function, *i.e.,* distribution or generation.

k. "Commission" or "CPUC" means the California Public Utilities Commission.

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 Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. The current rate structure, consisting of Customer Charges, Energy Charges and Non-Energy Charges shall be maintained for all applicable Street Light Rate Group and traffic control rate schedules.

b. Effective October 1, 2009, the following Customer Charges shall be applicable: for traffic control (Schedule TC-1), $14.75 per month per meter, for metered street lights with multiple service (Schedule LS-3), $13.00 per month per meter, and for metered street lights with series service (Schedule LS-3), $746.19 per month per meter.

c. Non-Energy Charges shall change only according to the provisions set forth in Paragraph 4 of this Agreement and only by SCE advice letters filed in compliance with the provisions of Paragraph 4 of this Agreement.

Illustrative changes to Non-Energy Charges calculated in accordance with these provisions are provided in Attachment A to this Agreement.

d. In order to achieve a greater degree of control over future increases to the Non-Energy Charges, a targeted annual percentage increase of 4.8 percent (based on the average Handy-Whitman[1] escalation rate for mast arms and luminaries installed for the period 2003-2008) to Non-Energy Charges shall be established for schedules LS-1, LS-2, LS-3, DWL, and OL-1. This target annual percentage increase shall be used to calculate Target Lamp Charges for each Streetlight rate schedule in 2009, 2010, 2011, and 2012. The Target Lamp Charges for 2009 shall equal the December 2008 Non-Energy Charges increased by 4.8 percent. For each year thereafter from 2010 until rate changes are implemented as a result of Phase 2 of SCE's 2012 GRC, the Target Lamp Charges shall equal the product of the Target Lamp Charges for the prior year increased by 4.8 percent.

e. Non-Energy Charges for 2009 that are implemented in accordance with Decision (D.) 06-06-067 and the settlement agreement adopted in Phase 2 of SCE's 2006 GRC (Application 05-05-023) will be in effect prior to October 1, 2009. Those Non-Energy Charges are expected to exceed the Target Lamp Charges for 2009. If so, there will be no increase to Non-Energy Charges when rate changes related to Phase 2 of SCE's 2009 GRC are first implemented on or after October 1, 2009. If Non-Energy Charges in effect prior to October 1, 2009 do not exceed the Target Lamp Charges for 2009, SCE shall increase such Non-Energy Charges to the Target Lamp Charges for 2009 when rate changes related to Phase 2 of SCE's 2009 GRC are first implemented on or after October 1, 2009.

f. This Agreement shall apply to increase Non-Energy Charges when attrition revenue changes authorized by the Commission in Phase 1 of SCE's 2009 GRC are implemented in 2010 and 2011, and when the

[1] The Handy-Whitman Index of Public Utility Construction Costs, "Cost Trends of Electric Utility Construction, Pacific Region" compiled and published by Whitman, Requardt & Associates, LLP

revenue change for Phase 1 of SCE's 2012 GRC is implemented, subject to the following conditions:

1. Non-Energy Charges for 2010 (adjusted for the 2009 GRC attrition year 2010 revenue increase) shall increase based on the functional System Average Percentage Change (SAPC) if the actual Non-Energy Charge in effect prior to January 1, 2010 is less than the Target Lamp Charge for 2010 provided that the Non-Energy Charge for 2010 shall not exceed the Target Lamp Charge for 2010. If however, the actual Non-Energy Charge in effect prior to January 1, 2010 exceeds the Target Lamp Charge for 2010, the Non-Energy Charge for 2010 shall not change.
2. Non-Energy Charges for 2011 (adjusted for the 2009 GRC attrition year 2011 revenue increase) shall increase based on the functional SAPC if the actual Non-Energy Charge in effect prior to January 1, 2011 is less than the Target Lamp Charge for 2011 provided that the Non-Energy Charge for 2011 shall not exceed the Target Lamp Charge for 2011. If however, the actual Non-Energy Charge in effect prior to January 1, 2011 exceeds the Target Lamp Charge for 2011, the Non-Energy Charge for 2011 shall not change.
3. When the revenue requirement change for SCE's 2012 GRC is implemented, Non-Energy Charges for 2012 shall increase based on the functional SAPC if the actual Non-Energy Charge in effect prior to January 1, 2012 is less than the Target Lamp Charge for 2012 provided that the Non-Energy Charge for 2012 shall not exceed the Target Lamp Charge for 2012. If however, the actual Non-Energy Charge in effect prior to January 1, 2012 exceeds the Target Lamp Charge for 2012, the Non-Energy Charge for 2012 shall not change.

g. Any revenue deficiency associated with the establishment of Non-Energy Charges for Street Light Rate Group rate schedules in accordance with Paragraphs 4.e and 4.f of this Agreement shall be recovered from all rate groups, with the deficiency allocated on the basis of distribution related revenues. This provision is subject to the filing in this proceeding and CPUC approval of a separate revenue allocation settlement agreement which also adopts the substance of this paragraph.

h. Changes to Allocated Revenues collected by Energy Charges and Customer Charges for the Street Light Rate Group and traffic control schedules shall be implemented on a Functional SAPC basis whenever changes to SCE's authorized revenues are implemented.

i. Distribution-related revenue allocations will not include streetlight facilities-related costs (*i.e.*, Non-Allocated Revenues) in determining the Street Light Rate Group's revenue responsibility.

j. Effective January 1, 2010, the costs for a Standard Installation defined in Special Condition 2 of Schedule LS-1 and used to establish a Differential Facilities rate, pursuant to Special Condition 11 of Schedule LS-1, shall equal the December 2009 Standard Installation costs increased by 4.8 percent. For each year thereafter until rate changes are implemented as a result of Phase 2 of SCE's 2012 GRC, the Standard Installation cost shall equal the product of the Standard Installation cost for the prior year increased by 4.8 percent.

k. SCE and CAL-SLA shall work together on a joint study prior to SCE's next GRC to better understand the costs to construct, install, own, and maintain street light facilities and to identify the sources of revenues that pay for the recovery of these costs.

l. Schedule AL-2 shall be modified to include two options: Option A and Option B. Outdoor area lighting customers without daytime incidental loads shall receive service on Schedule AL-2, Option A. Schedule AL-2, Option A, shall retain the same limits on incidental load and rate structure as in SCE's existing Schedule AL-2.

m. Schedule AL-2, Option B, shall allow incidental load up to 15 percent of the maximum monthly peak demand, whether such incidental load occurs in the daytime or nighttime, provided that daytime incidental load shall not exceed 20 kilowatts (kW). Schedule AL-2, Option B, shall also require a meter capable of providing interval metering data, which shall be provided by SCE, subject to meter availability, with no incremental meter charges.

n. Schedule AL-2, Option B, shall consist of on-peak and off-peak energy charges as well as a customer charge. The on-peak energy charge shall be equal to the Schedule GS-1 seasonal energy charge and shall apply year-round during the hours of 8:00 am to 4:00 pm on weekdays, weekends, and holidays. The off-peak energy charge for Schedule AL-2, Option B, shall be the same as the energy charge for Schedule AL-2, Option A. The customer charge for Schedule AL-2, Option B, shall be the same as the customer charge for Schedule AL-2, Option A.

o. Customers with outdoor area lighting service shall be removed from service on either Option A or Option B of Schedule AL-2 if the applicable incidental load limits are exceeded during any three months in a twelve-month period.

5. **Implementation of Agreement**

It is the intent of the 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 October 1, 2009.

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 Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

7. **Signature Date**

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

8. **Regulatory Approval**

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

9. **Compromise Of Disputed Claims**

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

10. **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.

11. **Previous Communications**

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties.

12. **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.

13. Effect Of Subject Headings

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

14. 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.

15. 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 Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: 1/19/2009

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ Reed V. Schmidt

Title: Energy Consultant Date: 1/8/2009

PLEASANT VALLEY RECREATION AND PARK DISTRICT

By: /s/ Mark Carlson

Title: Financial Supervisor Date: 1/8/2009

Attachment A

Illustrative Changes to Non-Energy Charges (2009 – 2012)

Illustrative Changes to Non-Energy Charges (2009 - 2012)
Pursuant to Paragraph 4 of Settlement Agreement

Example: 100-watt HPSV, Schedule LS-1

Year	Target Lamp Charge (2009 - 2012)	Assumed SAPC % Increase	Calculated SAPC Non-Energy Charge	Actual Non-Energy Charge
1-Dec-2008				$8.16
1-Jan-2009	$8.55	3.3%	$8.43	$8.43
1-Mar-2009		8.2%	$9.12	$9.12
1-Oct-2009		0.0%	$9.12	$9.12
1-Jan-2010	$8.96	5.0%	$9.58	$9.12
1-Jan-2011	$9.39	4.0%	$9.48	$9.39
1-Jan-2012	$9.84	6.0%	$9.95	$9.84

Settlement effective on October 1, 2009

(END OF ATTACHMENT F)

ATTACHMENT G

Commercial Submetering 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, And Design Rates	)	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	)	Application 07-12-020 (Filed December 21, 2007)

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC

PHASE 2 COMMERCIAL SUBMETERING SETTLEMENT AGREEMENT

Dated: January 12, 2009

#1591782-v6

Commercial Submetering Settlement Agreement

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC
PHASE 2 COMMERCIAL SUBMETERING SETTLEMENT AGREEMENT

This Phase 2 Commercial Submetering Settlement 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), Simon Property Group (Simon); and the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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. Simon is a fully integrated real estate company with an interest in over 350 shopping centers worldwide, including properties located in the SCE service area.

c. BOMA consists of associations of commercial real estate professionals that own, manage, or otherwise service commercial office buildings in SCE's service territory and within California. BOMA members own or manage in excess of 600 million square feet of commercial office space that is occupied by small and medium sized businesses.

2. **Recitals**

a. In Phase 2 of SCE's 2009 General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008. In its testimony, SCE proposed to revise its Rule 18 to allow owners of certain commercial buildings to submeter their tenants in connection with the provision of electricity and subject to certain terms and conditions (SCE Submetering Proposal). The purpose of submetering is to provide nonresidential tenants price signals and information about their energy usage and costs, and to provide the opportunity for tenants to participate in energy conservation or load management programs.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 12, 2008.

d. DRA served its initial testimony on September 26, 2008. Interveners, including Simon and BOMA served their initial testimony on October 31, 2008.

e. Simon served its testimony on October 31, 2008. That testimony supported SCE's Submetering Proposal but opposed SCE's limitation of commercial submetering to high-rise buildings.

f. BOMA served its testimony on October 31, 2008. That testimony supported SCE's Submetering Proposal. However, BOMA proposed to achieve a settlement so that commercial submetering could go into effect in SCE's service territory by January 1, 2009, instead of October 1, 2009.

g. The Energy Division of the Commission expressed an interest to SCE and the parties that SCE customers who were interested in pursuing commercial submetering should be made aware of certain protective provisions that were proposed by TURN in a PG&E proceeding (A.06-03-005) and were adopted by the Commission in D.07-09-004.

h. Continuing settlement discussions occurred among the interested parties after November 12, 2008.

i. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to commercial submetering as indicated in Paragraph 4 of this Agreement.

3. **Definitions**

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

b. "Commission" or "CPUC" means the California Public Utilities Commission.

c. "Premises" shall have the meaning as defined in SCE's Rule 1, which is entitled "Definitions."

d. "Settling Parties" means SCE, Simon, and BOMA.

e. "Rule 18" means SCE's tariff, which is entitled "Supply to Separate Premises and Use by Others" that deals with, among other things, the metering and provision of electricity to tenants in nonresidential buildings or developments on a single Premises.

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 Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Settling Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Settling Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent and timely implementation of all the provisions of the Agreement.

a. SCE shall continue to require a single meter for each tenant or enterprise located in a single, nonresidential premises except where such service in SCE's opinion is impractical or where the Commission has authorized SCE to supply electric service through a single meter pursuant to Rule 18, as revised by this Settlement Agreement. A revised Rule 18 is set forth in Attachment A to this Settlement Agreement.

b. Where SCE provides electric service through a single meter to a customer's nonresidential premises, nonresidential tenants at the premises may be submetered and billed for electric service, irrespective of whether the premises is a high-rise building, subject to the following conditions:

1. Submetering of electric usage by nonresidential tenants shall be subject to the mutual agreement of the customer and the nonresidential tenant.
2. A customer who provides submetered service to nonresidential tenants shall be allowed to recover the costs of metering, billing, and information services, according to terms jointly agreed to by tenants and the customer and specified in leases. Nothing in this Agreement prevents the customer from separately charging tenants for submetering and energy information services, including the amortized cost of re-wiring, meter and data server hardware and software costs, and ongoing meter and meter data systems

operations, maintenance and administrative costs, as authorized by the Commission in D.07-09-004 and according to terms jointly agreed to by tenants and a customer and specified in leases.

3. The customer shall provide all nonresidential tenants with the following information:
    a. The SCE rate schedule that applies to service to the customer.
    b. Contact information for SCE customer service.
    c. Contact information for the California Department of Food and Agriculture, Division of Measurement Standards meter complaint process.
    d. Information concerning dynamic pricing options and all energy conservation and load management programs available for tenant participation.
4. The customer shall install and maintain meters of comparable accuracy as utility revenue meters for nonresidential tenants, subject to all applicable safety rules, regulations, and general orders established by the State of California and its subdivisions and local governments and their subdivisions. Common areas shall be separately metered.
5. The rates and charges billed to nonresidential tenants by the customer for the electricity provided by SCE to the customer and used by such tenants shall be the same as the total amount billed by SCE to the customer. The customer shall apportion or prorate fixed monthly charges (*e.g.*, customer or demand) among the submetered tenants such that the total amount billed to submetered tenants equals the amount billed by SCE to the customer.
6. Bills for tenant electric usage shall resemble bills rendered by SCE for comparable service and must include the following information:

a. Energy (kWh) and demand (kW) and associated charges by time-of-use (TOU) period in the same level of detail as shown on SCE's bill to the customer.

b. Energy and demand charges allocated to the tenant for common area usage, and other consumption exclusive of tenant measured usage. Such allocations should be in accordance with methods specified in leases (such as square footage of occupied space) and shall not be based on tenant measured usage.

c. Charges for submetering, and billing and information services provided by the customer.

d. Sufficient information to permit tenants to replicate customer's bill calculations.

7. When a customer at an existing premises where energy charges for tenants are absorbed in a lease begins billing tenants for submetered electric service, the customer shall account for and credit tenants' rental charges to reflect removal of the related tenant-controlled energy charges on a prospective basis for the duration of the lease.

c. Customers or representatives of customers who provide submetered service to nonresidential tenants should provide information to SCE that is necessary to evaluate the effects of this commercial submetering service on energy consumption of nonresidential tenants. Provided that sufficient information is available, SCE's testimony in Phase 2 of SCE's 2012 GRC will include the results of a survey regarding the impact on electric usage of submetered nonresidential tenants.

5. <u>Implementation of Agreement</u>

It is the intent of the Settling Parties that SCE should be authorized to implement the revisions to Rule 18 resulting from this Agreement as soon as practicable following the issuance of a final Commission decision approving this Agreement.

6. <u>Incorporation of Complete Agreement</u>

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 Settling Party or the 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.

7. <u>Signature Date</u>

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

8. <u>Regulatory Approval</u>

The Settling Parties shall use their best efforts to obtain timely Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

9. <u>Compromise Of Disputed Claims</u>

This Agreement represents a compromise of disputed claims among the Settling Parties. The Settling Parties have reached this Agreement after taking into account the possibility that each Settling 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.

10. <u>Non Precedent</u>

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.

11. Previous Communications

The Agreement contains the entire agreement and understanding between and among the Settling Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between and among the Settling Parties.

12. Non Waiver

None of the provisions of this Agreement shall be considered waived by any Settling Party unless such waiver is given in writing. The failure of a Settling 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.

13. Effect Of Subject Headings

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

14. 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.

15. 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 represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: 1/20/2009

SIMON PROPERTY GROUP, INC.

By: /s/ S.F. Greenwald

Title: Attorney Date: 1/20/2009

BOMA

By: /s/ B. F. Roberts

Title: President, Economic Sciences Corp. Date: 1/15/2009

Attachment A

Proposed SCE Rule 18

Rule 18 Sheet 1

SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS

A. Separate Metering. Separate Premises will not be supplied through the same meter nor will the electric loads of such separately metered Premises be aggregated physically, electronically or otherwise, except as may be specifically provided for in the tariff schedules.

B. Nonresidential Loads. In accordance with Rule 16, electric service shall be individually metered to each tenant in a non-residential building or group of buildings or other development on a single Premises with multiple tenants or enterprises. However, where, in the opinion of SCE, it is impractical to meter each tenant individually or where the Commission has authorized SCE to supply electric service through a single meter, SCE may provide service through a single meter subject to the provisions of Sections E and H below.

Buildings originally constructed for a non-residential purpose that subsequently converted to residential use on or after December 7, 1981 without the need for a building permit shall be eligible to convert from their prior rate schedule to an existing applicable domestic service submetering rate schedule. Any non-residential building converted to residential use, for which a building permit was required on or after July 1, 1982, must be separately metered by SCE.

C. Other Uses or Premises. A customer shall not use electricity received from SCE upon other Premises, except for SCE's operating convenience, nor for other purposes than those specified in the customer's application or in the rate schedule applied.

D. Customer with Multiple Service Accounts/Meters at a Single Premises. When a customer (single enterprise) occupies a single Premises with multiple service accounts/meters, the readings of such meters shall not be combined for billing purposes except as provided for in Rule 9.B. However, if the customer physically aggregates the electric loads of such multiple service accounts/meters into a single service account (master meter), the account will be provided service under an applicable rate schedule.

E. Use by Others. A customer shall not charge for electricity received from SCE and used by another person, except:

1. Where energy is purchased at rates specifically applicable to resale service; or

2. Where the charge to domestic or nondomestic tenants is absorbed in the rental for the Premises or space occupied, is not separately identified, and does not vary with electrical usage, or where all of the following conditions are met for non-domestic service: (C)(L)

   a. Service to the customer is supplied to a single meter (master meter) located in a commercial building or development on a single Premises; (N)

   b. The customer installs and maintains meters of comparable accuracy as utility revenue meters for nondomestic tenants subject to all applicable safety rules, regulations, and general orders established by the State of California and its subdivisions and local governments and their subdivisions.

   c. Submetering of electric usage by nondomestic tenants shall be subject to the mutual agreement of the customer and the nondomestic tenant. (N)

(Continued)

(Continued)

E. Use by Others. (Continued)

2. (Continued)

d. The customer shall provide all nondomestic tenants with the following information:

(1) The SCE rate schedule that applies to service to the customer.
(2) Contact information for SCE customer service.
(3) Contact information for the California Department of Food and Agriculture, Division of Measurement Standards meter complaint process.
(4) Information concerning dynamic pricing options and all energy conservation and load management programs available for tenant participation.

e. Bills for tenant electric usage shall resemble bills rendered by SCE for comparable service and must include the following information:

(5) Energy (kWh) and demand (kW) and associated charges by time-of-use (TOU) period in the same level of detail as shown on SCE's bill to the customer.
(6) Energy and demand charges allocated to the tenant for common area usage, and other consumption exclusive of tenant measured usage. Such allocations should be in accordance with methods specified in leases (such as square footage of occupied space) and shall not be based on tenant measured usage.
(7) Charges for submetering, and billing and information services provided by the customer.
(8) Sufficient information to permit tenants to replicate customer's bill calculation.

f. The rates and charges billed by the customer to nondomestic tenants, in total, for the electricity provided by SCE to the customer and used by such tenants shall be the same as the rates and charges billed by SCE to the customer. The customer shall apportion or prorate fixed monthly charges (e.g., customer, peak demand) among submetered tenants such that the total amount billed to submetered tenants equals the amount billed to the customer by SCE.

(Continued)

Rule 18 Sheet 3 (T)
SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS

(Continued)

E. Use by Others. (Continued)

2. (Continued)

g. When a customer at an existing Premises where energy charges for tenants are absorbed in a lease begins billing tenants for submetered electric service, the customer shall adjust rental charges such that charges for tenant-controlled energy usage are not also reflected in the lease. Charges for master metered customer-controlled energy usage (e.g., common area usage) may continue to be included in rental charges. (T) (L)

3. Where the customer is the owner, lessee, or operator of a multifamily accommodation and submeters electricity furnished for use by a domestic tenant in a single-family dwelling at the same rates that SCE would charge for the service if supplied directly and such customer's account is eligible for service under Schedule DMS-1 or DMS-2. In such cases, said owner, lessee, or operator shall furnish, install, maintain, and test the submeters. This electrical usage applies only to the single-family dwellings and excludes other electrical usage such as for swimming pools, recreation rooms, or laundry facilities which are used in common by tenants. In addition, said owner, lessee, or operator served under Schedule DMS-2 may elect to have SCE perform mobilehome park bill calculation services in accordance with the provisions contained within Schedule DMS-2 and Form 14-774, Bill Calculation Service Agreement. (L)

4. As provided in Sections F and G below.

All energy use, including use by others, supplied through a single SCE meter is the responsibility of the customer of record.

F. Privately or Publicly Owned Boat Marinas. SCE will furnish electrical service to a master-meter customer at a privately or publicly owned boat marina or small craft harbor. The master-meter customer may submeter tenant usage aboard a vessel moored in an individual slip or berth at the marina or harbor but may not submeter any other tenant or any land-based facility.

If the master-meter marina customer submeters and furnishes electricity to an individual boat slip or berth for tenant usage aboard a vessel, the rates and charges to the user must not exceed those that would apply if the user were purchasing such electricity directly from SCE. (L)

(Continued)

Rule 18 Sheet 4 (T)

SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS

(Continued)

G. Cold-Ironing Load. A master-metered customer may submeter a tenant's cold-ironing load aboard an ocean-going vessel at the Port of Long Beach or the Port of Hueneme but may not submeter any other load or land-based facility. (L)

If the master-metered customer submeters cold-ironing load to an ocean-going vessel, the rates and charges to the submetered user for services supplied by SCE must not exceed the rates and charges the master-metered customer is billed by SCE for such services.

Cold-ironing load is defined as the use of shore-supplied electricity for the lights, heating, cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines.

H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. (T)

Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G.

I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)

(END OF ATTACHMENT G)

ATTACHMENT H

Rate Design Guidance[1]

All Dynamic Pricing Rates

- Rate design should promote economically efficient decision-making.
- To promote economically efficient decision-making, rates should be based on marginal cost.
- Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.
- Rates should also seek to provide stability, simplicity and customer choice.
- If customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.
- Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.
- Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate.
- Utilities should offer optional bill protection to customers on default dynamic pricing rates.

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1 From Decision 08-07-045, Attachment A.

- The utilities should bid demand reductions due to dynamic pricing into the California Independent System Operator's (CAISO's) day-ahead market.

Critical Peak Pricing

- The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.

- The utility should explain what it used as the basis for the marginal cost of capacity in its critical peak pricing (CPP) rate and why. The annualized cost of a new combustion turbine is a reasonable proxy for determining the marginal capacity prices; however, alternative bases include actual utility costs, CAISO scarcity prices (if adopted by the Federal Energy Regulatory Commission and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented)

- Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates during non-critical periods.

- Since the critical peak price is intended to reflect the marginal cost of generation that is needed to meet peak period usage, CPP rates should not also have summer generation demand charges.

- The utilities should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.

- The utilities should be able to call critical peak events any day of the week, year round.

Real-Time Pricing

- The energy charge should be indexed to the CAISO's day-ahead hourly market prices.

- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered.

- The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices.

(END OF ATTACHMENT H)