

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

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| 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) |
| |) | |

**MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND
SETTLING PARTIES FOR ADOPTION OF MEDIUM AND LARGE POWER RATE
DESIGN SETTLEMENT AGREEMENT**

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Pursuant to Rule 12.1 *et seq* of the Commission’s Rule of Practice and Procedure, Southern California Edison Company (SCE), on behalf of itself and the Settling Parties,¹ requests that the Commission adopt and find reasonable the “Phase 2 Medium and Large Power Rate Design Settlement Agreement,” (Settlement Agreement) which is appended to this motion as Attachment A.

The Settling Parties have reached a Settlement Agreement that resolves all issues related to rate design for rate schedules in the Medium and Large Power rate groups in Phase 2 of SCE’s 2009 General Rate Case (GRC). As soon as practicable following a Commission decision adopting the Settlement Agreement, but no earlier than October 1, 2009, SCE will adjust its rates

¹ 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”), and the Energy Producers and Users Coalition (EPUC) are collectively referred to herein as the Settling Parties.

for customers served on rate schedules in these rate groups pursuant to the terms of the Settlement Agreement.²

Section I of this motion provides background related to this proceeding. Section II describes in general the terms of the Settlement Agreement. Section III demonstrates that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest, and that it should be adopted without modification. Section IV discusses the requests of the Settling Parties related to processing of this request and implementation of new rates.

I.

BACKGROUND

This proceeding was initiated by the filing of SCE's application on March 4, 2008, along with SCE's direct testimony. SCE updated its initial evidentiary showing on June 27, 2008. DRA served its initial testimony on September 26, 2008. Interveners served their testimony on October 31, 2008. In accordance with the "Scoping Memo and Ruling of Assigned Commissioner," dated May 14, 2008, SCE provided notice to all parties of a settlement conference to be held on November 12, 2008. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the November 12, 2008 settlement conference. Given progress made toward settlement, rebuttal testimony was deferred pursuant to rulings by Administrative Law Judge (ALJ) Yip-Kikugawa. SCE and the Settling Parties executed this Settlement Agreement on or after February 4, 2009.

The Settling Parties represent medium and large commercial customer interests. SCE, FEA, CMTA, CLECA, EUF, the Solar Alliance, BOMA, Debenham, and EPUC served prepared direct testimony that addressed the issues resolved by this Settlement Agreement. These proposals would have resulted in a wide range of outcomes relative to SCE's litigation position.

² This Settlement Agreement also assumes Commission approval of the Phase 2 Revenue Allocation Settlement Agreement, filed January 9, 2009, which is intended to establish the allocation of SCE's revenue requirement among all customer groups.

II.

SUMMARY OF THE SETTLEMENT AGREEMENT

Some of the primary provisions of the Settlement Agreement are summarized below.

A. Common Pricing Criteria

The Settlement Agreement establishes certain common pricing criteria for the GS-2, TOU-GS-3, and TOU-8 rate groups as follows:

Customer charges shall be set at the full equal percent of marginal cost (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 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, 2009.³

SCE's CPP tariff shall allow no more than 15 but no less than 9 events, and is designed to be activated for 12 events per year and may occur only during the time period from 2:00 p.m. to 6:00 p.m. 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. In order to minimize and account for revenue imbalances, the undercollection or overcollection in rates 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 rate group that is responsible for the amount of the revenue imbalance.⁴

³ Settlement Agreement, ¶4.a.1

⁴ Settlement Agreement, ¶4.a.7.c.

B. TOU-8 Rate Groups

The default rate schedules shall include CPP pricing components, with bill protection for the first 12 months of service. Customers shall have the option to be served on other applicable rate schedules. 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. Schedule TOU-8 Option B shall be the OAT for customers in the large power rate groups (who opt out of the CPP overlay tariff) and shall include customer charges, energy charges, and demand charges, designed as specified in the Agreement. An experimental rate shall be offered as an optional rate schedule for customers who employ solar, wind, fuel cells, and other designated technologies with net capacities 15 percent or greater than the customer's annual peak demand.

C. GS-2 and TOU-GS-3 Rate Groups

The Settlement Agreement provides estimated customer charges, facilities-related demand charges, time-related demand and energy charges and methods to adjust such charges based on the outcome of SCE's authorized revenue requirement changes that occur after the Agreement has been implemented. Customers with peak demands of 20 kW to 199 kW shall take service on a default basis on an applicable non-TOU rate schedule (i.e., Schedule GS-2) with eligibility to participate in a CPP tariff.⁵ Such customers may also take service on a TOU rate schedule, e.g. Schedule GS-2-TOU, Option A or Option B.⁶

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 from the default CPP tariff to Schedule TOU-GS-3, Option B or to other applicable tariffs.⁷

The Settlement Agreement provides for an electric vehicle rate schedule TOU-EV-4, in which off-peak energy charges will provide discounted off-peak charging rates, subject to a floor

⁵ Settlement Agreement, ¶4.c.1

⁶ Settlement Agreement, ¶4.c.1

⁷ Settlement Agreement, ¶4.c.4

price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges as defined by D.07-11-052.⁸

III.

REQUEST FOR ADOPTION OF THE SETTLEMENT AGREEMENT

This Settlement Agreement is submitted pursuant to Rule 12.1 *et seq* of the Commission's Rules of Practice and Procedure. The Settlement Agreement is consistent with Commission decisions on settlements which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.⁹ This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.¹⁰ As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest it should be adopted without change.

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

The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.¹¹

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

⁸ Settlement Agreement, ¶4.c.6.

⁹ *See, e.g.*, D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).

¹⁰ D.92-12-019, 46 CPUC 2d 538, 553.

¹¹ *See also, Re San Diego Gas & Electric Company*, (D.90-08-068), 37 CPUC 2d 360: “[S]ettlements brought to this Commission for review are not simply the resolution of private disputes, such as those that may be taken to a civil court. The public interest and the interest of ratepayers must also be taken into account and the Commission's duty is to protect those interests.”

A. The Settlement Is Reasonable In Light Of The Record

The prepared testimony, the Settlement Agreement itself, and this motion contain the information necessary for the Commission to find the Settlement Agreement reasonable in light of the record. Prior to the settlement, parties conducted discovery, and served testimony on the issues related to rate design for the medium and large power rate groups. The prepared testimony and related exhibits have been made part of the Commission's record of this proceeding.

The Settlement Agreement represents a reasonable compromise of the parties' positions. The prepared testimony of the parties, comprising the record for this proceeding, contains sufficient information for the Commission to judge the reasonableness of the Settlement Agreement.

B. The Settlement Agreement Is Consistent With Law

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

C. The Settlement Agreement Is In The Public Interest

The Settlement Agreement is a reasonable compromise of the Settling Parties' respective positions. The Settlement Agreement is in the public interest and in the interest of SCE's customers. It fairly resolves issues and provides more certainty regarding their future rates, which is in the public interest. The Settlement Agreement, if adopted by the Commission, avoids the cost of further litigation, and frees up Commission resources for other proceedings. Given that the Commission's workload is extensive, the impact on Commission resources is doubly important. The Settlement Agreement frees up the time and resources of other parties as well, so that they may focus on other proceedings. The prepared testimony and evidentiary record

contain sufficient information for the Commission to judge the reasonableness of the Settlement Agreement and for it to discharge any future regulatory obligations with respect to this matter.

Each portion of the Settlement Agreement is dependent upon the other portions of the Settlement Agreement. Changes to one portion of the Settlement Agreement would alter the balance of interests and the mutually agreed upon compromises and outcomes which are contained in the Settlement. As such, the Settling Parties request that it be adopted as a whole by the Commission, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

IV.

SCHEDULE FOR COMMENTS AND IMPLEMENTATION OF SETTLEMENT AGREEMENT

The Settling Parties seek approval of the terms of the Settlement Agreement so that SCE may implement rates as soon as practicable following the issuance of a final Commission decision approving the Settlement Agreement but no earlier than October 1, 2009.¹² Given that hearings on this Settlement Agreement have been scheduled on February 9 or 10, 2009, the Settling Parties recommend that any written comments on the Settlement Agreement be provided at the time opening briefs are due on February 20, 2009 and that any reply comments be filed when reply briefs are due on March 6, 2009.

V.

CONCLUSION

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

1. Shorten the period allowed for comments and replies on the Settlement Agreement;
2. Adopt the attached Settlement Agreement as reasonable in light of the record, consistent with law, and in the public interest; and

¹² With respect to the proposed electric vehicle rate schedules, SCE requests that it be authorized to implement revised rates as soon as practicable after a Commission decision approving this Settlement Agreement.

Attachment A

Medium and Large Power Rate Design Settlement Agreement

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

Dated: [January 29, 2009](#)

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

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Appendix A - Illustrative Rates for Medium and Large Power Rate Schedules

**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 Supplemental Service Time-Related Demand Charge to the

Backup 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 ERRRA 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 B

Medium and Large Power Rate Design Illustrative Rates

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

| | | Rates Effective December 2008 | | | Settlement Rates | | | Total Rate Change |
|---|--------------------|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| | | Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |
| Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement. | | | | | | | | |
| 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 | | | Total Rate Change |
|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |

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

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 | | | Total Rate Change |
|---|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| | Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |
| 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.

TOU-GS-3 (Option B)

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Off-Peak

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

above 50 kV

TOU-GS-3 (Both Options)

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

above 50 kV

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

above 50 kV

Power Factor Adjustment - \$/kVA

Greater than 50 kV

50 kV or less

CARE Energy Discount - %

| | Rates Effective December 2008 | | | Settlement Rates | | | Total Rate Change |
|------------------------------------|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| | Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |
| 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% |
| 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 | | | | | | | |
| 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% |
| Mid-Peak | 0.00 | 0.00 | 0.00 | | | | |
| Off-Peak | 0.00 | 0.00 | 0.00 | | | | |
| 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% |
| 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% |
| 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% |
| 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 | | | Total Rate Change |
|---|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| | Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |
| 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-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 | |
| 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 | |

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 | | | Total Rate Change |
|--|----------------------------------|------------|------------|------------------|------------|------------|----------------------|
| | Delivery | Generation | Total Rate | Delivery | Generation | Total Rate | |
| 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% |
| Backup Service | | | | | | | |
| Demand Charge - \$/kW | | | | | | | |
| 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% |
| Phase-in | | | | | | | |
| 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% |

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.

TOU-8 (Below 2kV) - Option A

Energy Charge - \$/kWh

Summer Season

On-Peak
Mid-peak
Off-Peak

0.01785 0.31856 0.33641
0.01785 0.12672 0.14457
0.01785 0.05739 0.07524

Winter Season

Mid-peak
Off-Peak

0.01785 0.07626 0.09411
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

TOU-8 (From 2 kV to 50 kV) - Option A

Energy Charge - \$/kWh

Summer Season

On-Peak
Mid-peak
Off-Peak

0.01734 0.32331 0.34065
0.01734 0.12632 0.14366
0.01734 0.05596 0.07330

Winter Season

Mid-peak
Off-Peak

0.01734 0.07431 0.09165
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
Mid-peak
Off-Peak

0.01499 0.27391 0.28890
0.01499 0.10542 0.12041
0.01499 0.04695 0.06194

Winter Season

Mid-peak
Off-Peak

0.01499 0.06565 0.08064
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

| Rates Effective December 2008 | | |
|----------------------------------|------------|------------|
| Delivery | Generation | Total Rate |

| Settlement Rates | | |
|------------------|------------|------------|
| Delivery | Generation | Total Rate |

| |
|----------------------|
| Total Rate Change |
|----------------------|

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 |
|----------------------|

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

| | | | |
|--|---------|---------|---------|
| <i>TOU-GS-3</i> | | | |
| 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) |
| <i>TOU-8-SEC</i> | | | |
| 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) |
| <i>TOU-8-PRI</i> | | | |
| 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) |
| <i>TOU-8-SUB</i> | | | |
| 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) |

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 | | | |

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.

TOU-8 (Below 2kV) - Option R

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Off-Peak

Power Factor Adjustment - \$/kVA

| Rates Effective December 2008 | | |
|----------------------------------|------------|------------|
| Delivery | Generation | Total Rate |
| | | |

| Settlement Rates | | |
|------------------|------------|------------|
| Delivery | Generation | Total Rate |
| | | |

| Total Rate Change |
|----------------------|
| |

0.03174 0.31856 0.35030
0.03174 0.12672 0.15846
0.03174 0.05739 0.08913

0.03174 0.07626 0.10800
0.03174 0.05431 0.08605

542.25 542.25

5.85 5.85

0.27 0.27

TOU-8 (From 2 kV to 50 kV) - Option R

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Off-Peak

Power Factor Adjustment - \$/kVA

0.02937 0.32331 0.35268
0.02937 0.12632 0.15569
0.02937 0.05596 0.08533

0.02937 0.07431 0.10368
0.02937 0.05222 0.08159

291.00 291.00

5.48 5.48

0.27 0.27

TOU-8 (Above 50 kV) - Option R

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Off-Peak

Power Factor Adjustment - \$/kVA

0.01692 0.27391 0.29083
0.01692 0.10542 0.12234
0.01692 0.04695 0.06387

0.01692 0.06565 0.08257
0.01692 0.04662 0.06354

2232.25 2232.25

3.48 3.48

0.32 0.32



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