ATTACHMENT A

PHASE 2 SETTLEMENT AGREEMENT

<u>SETTLEMENT OF ISSUES RELATED TO MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON'S 2003 GENERAL RATE CASE (PHASE 2 SETTLEMENT AGREEMENT)</u>

Dated: **November 1, 2004**

SETTLEMENT IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON'S 2003 GENERAL RATE CASE

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SETTLEMENT OF ISSUES RELATED TO MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON'S 2003 GENERAL RATE CASE (PHASE 2 SETTLEMENT AGREEMENT)

This Phase 2 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); The Utility Reform Network (TURN); the Office of Ratepayer Advocates (ORA); 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); Indicated Commercial Parties (ICP); Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties);[1] California City-County Street Light Association (CAL-SLA); Natural Resources Defense Council (NRDC); the Western Manufactured Housing Communities Association (WMA); the Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC); and Manfred Gildner[2] (referred to hereinafter collectively as Parties or individually as Party).

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1 On October 19, 2004, the Joint Parties Interested in Distributed Generation/Distributed Energy Resources notified the parties to this proceeding that its name had changed to the California Clean DG Coalition.

2 Mr. Gildner is an SCE customer who intervened in this proceeding and raised an issue regarding the baseline allocation provided to a small number of customers in a portion of the city of San Bernardino. That issue is addressed in 6.c.ii.k, below.

2. Recitals

a. SCE is an investor-owned public utility and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

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

c. ORA 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 ORA 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 89,000 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. 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 or direct access customers.

h. 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.

i. 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, Catholic Healthcare West, and Lowe's Home Improvement Warehouses, Inc.

j. Joint Parties is an ad hoc coalition of entities interested in short- and long-term issues and policies of import to distributed energy resources system manufacturers, distributors, marketers, investors and customers.

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

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

m. NRDC is a non-profit environmental organization with a long-standing interest in minimizing the societal costs of reliable energy services.

n. CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

o. 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, ExxonMobil Power & Gas Services, Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California

3. Background

a. In Phase 2 of SCE's 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. In conformance with the Commission's objectives and practices, pricing proposals in this proceeding are designed to reflect SCE's cost of providing service. The Commission has consistently held that marginal costs should be the basis for the revenue allocation and rate design processes so that customers receive accurate price signals associated with their usage characteristics.

b. On October 30, 2002, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design. SCE updated its initial showing on March 23, 2003. ORA served its initial testimony on July 1, 2003. Interveners served testimony on

August 29, 2003, and parties served rebuttal testimony on September 30, 2003.

c. On December 3, 2003, SCE provided notice to all parties of its intent to conduct a telephonic conference related to potential settlement of issues. An initial settlement conference was held on December 12, 2003. Additional settlement conferences have occurred over a considerable period of time among parties related to the potential settlement of issues in this proceeding.

d. A settlement approved by the Commission in D. 03-07-029, precluded any SCE revenue allocation and rate design changes until no earlier than August 2004. The Commission issued D. 04-07-022 in Phase 1 of this application on July 8, 2004. Following that decision, the parties evaluated the impacts of the various proposals in Phase 2 of this proceeding, and have reached agreement as indicated in Paragraph 6 of this Agreement.

4. <u>**Comparison Exhibit**</u>

As required by Rule 51.1(c), because this settlement pertains to a proceeding under the Rate Case Plan, a comparison of SCE's and ORA's respective litigation positions to the outcome of the Settlement Agreement is provided in Appendix A.

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

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

d. "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.

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

f. "Loss of Load Probability" means the probability that available generation capacity will be inadequate to supply customer demand at any given moment.

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

h. "NCO" means New Customer Only, and is an allocation method that takes into account only the capital cost of adding new customers.

i. "NGO" means Net Generation Output and refers to a meter located on a customer's generating unit.

j. "Primary Voltage" means facilities at which electric power is taken or delivered, generally between 12 kV and 33 kV.

k. "Ratchet Provision" means the provision applied to certain of SCE's demand-metered rate schedules by which customers are charged the greater of the registered monthly maximum demand for the current month or a specified percentage of the customer's maximum monthly demand registered during the previous eleven months.

l. "Rate Case Plan" means D. 89-01-040, as modified by D. 93-07-030 for processing by the Commission of SCE rate cases.

m. "Real Economic Carrying Charge" means a measure of the per dollar savings of deferring an investment one year, taking into account the stream of replacement investments.

n. "Secondary Voltage" means facilities at which electric power is taken or delivered, generally between 120 volts and 480 volts.

o. "Settling Parties" means SCE, ORA, TURN, CFBF, AECA, ICP, Joint Parties, CMTA, CLECA, FEA, WMA, CAL-SLA, NRDC, and CAC/EPUC.

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

q. "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.

r. "Trust Transfer Amount"' means the revenues collected via non-bypassble charges from customers in the residential and small commercial customer rate groups that were eligible for the 10 percent rate reduction implemented in accordance with Public Utilities Code Section 368. This revenue is used to pay principal and interest on the bonds that were used to finance the 10 percent rate reduction.

6. **Agreement**

In consideration of the mutual obligations, covenants and conditions contained herein, the 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 12 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) **Marginal Costs**

The Settling Parties agree to the following regarding marginal costs:

(1) **Generation Marginal Costs, Energy and Capacity**

Marginal energy costs are based on a forecast gas price of $4.63 per million BTUs and based on SCE's proposed methodology set forth in Exhibit SCE-31. Marginal generation capacity cost is based on the cost of a gas-fired combustion turbine (CT), with its installation cost annualized using the Real Economic Carrying Charge (RECC) methodology. This Agreement is based on a CT proxy cost of $78 per kW per year. Generation marginal costs by season and time periods are as follows:

Generation Marginal Cost (2004$)					
	Summer			Winter	
	On	Mid	Off	Mid	Off
Energy Cost (c/kWh)	4.61	4.05	3.21	4.23	3.34
CT Proxy ($/kW):	66.56	5.66	0	7.56	0
Average 79.78					

Notes: Energy Cost is a two year simple average (2004-2005). The corresponding natural gas price is $4.63 per MMBtu.

CT-Proxy is the CEC Forecast of $78/kw adjusted to 2004$ and including a working cash loader

(2) Marginal Customer Cost

Marginal Customer Costs are based on the use of the New Customer Only (NCO) method.

Rate Group	NCO - $/customer-month
Domestic	4.84
GS-1	4.88
TC-1	4.44
GS-2	64.84
TOU-GS-2	60.27
TOU-8-Sec	456.51
TOU-8-Pri	89.92
TOU-8-Sub	1,564.50
PA-1	13.45
PA-2	39.63
AG-TOU	160.81
TOU-PA-5	160.81
Street Lighting	4.10

(3) Marginal Distribution Demand Cost

Calculated based on the regression of distribution investments at Primary and Subtransmission voltage levels against load growth on those systems using the traditional NERA regression methodology, without separation into design demand and grid infrastructure components as initially proposed by SCE. This method estimates the incremental cost of adding distribution capacity to meet demand, using ten years of historical data and a five-year forecast.

Distribution Marginal Cost (2004$)	
	System Design Demand ($/kW)
ISO Transmission (220 kV)	$10.40
Non-ISO Subtransmission (66 kV)	$17.30
Distribution (12 kV)	$51.46

b) **<u>Revenue Allocation</u>**

The Settling Parties agree that the revenue allocation results shown by rate groups that are depicted in Appendix B to this Agreement ("Phase 2 Revenue Allocation Agreement") are reasonable and should be adopted by the Commission. The Phase 2 Revenue Allocation Agreement reflects SCE's adopted revenue requirements for transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, trust transfer amount, and the DWR Power Charge and DWR Bond Charge revenue requirements. The contested revenue allocation issues in this proceeding primarily involve the allocation of the DWR Power Charge revenue requirement and SCE's distribution revenue requirement.

(1) **<u>Revenue Requirement and Allocation Principles</u>**

SCE's consolidated revenue requirement shall be allocated in terms of the following components and in the manner specified below:

a. Generation-Related Revenue Requirement
The generation-related revenue requirement consists of SCE's authorized generation revenue requirement and the DWR Power Charge revenue requirement. Pursuant to this Agreement, both the SCE generation revenue requirement and the DWR Power Charge

revenue requirement shall be allocated to rate groups based on marginal generation cost revenue responsibility. Marginal generation cost revenues are calculated based on the marginal generation costs listed in Paragraph 6.a)(1), above for bundled-service sales. In developing marginal generation cost revenue responsibility, marginal generation capacity costs shall be applied to rate groups based on their demands coincident with the top 100 hours of system load.

b. FERC-Jurisdictional, Transmission Revenue Requirement

FERC-approved rates for transmission and the 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 to calculate SCE's total delivery service rates.

c. Distribution-Related Revenue Requirement

1. SCE's CPUC-approved distribution revenue requirement shall be allocated to rate groups based on the sum of the marginal customer and distribution cost revenues. Marginal customer cost revenues are calculated based on the NCO method (ongoing O&M costs are applied to all customers in the rate group while capital costs are applied only to the growth in number of customers). Marginal distribution cost revenues are calculated by applying the marginal distribution 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 number of customers and sales, respectively.

2. Generation-related administrative and general (A&G) costs are recovered in SCE's distribution rate component pursuant to D. 04-07-022. Allocation of these costs shall be based on generation marginal cost revenues as defined above. Because generation-related A&G costs apply to all customers, the marginal generation cost allocator used herein shall reflect total retail load, including the load of DA customers.
3. Interruptible rate program credits shall be based upon SCE's forecast of program participation and credit levels. These costs shall be allocated to rate groups for recovery from bundled-service and DA customers based on the marginal generation cost allocator used for allocation of generation-related A&G costs to all customers, as described above.
4. Non-allocated revenues consist primarily of Street Lighting facilities costs and power factor adjustment revenues. These revenues shall be assigned directly to the rate groups responsible for incurring the costs. For purposes of this Agreement, non-allocated revenues (except for

power factor adjustment revenues which shall be updated) shall be maintained at levels currently reflected in SCE's rates.

5. The discount provided to SCE's employees under Schedule DE shall be allocated to all other customers, except customers receiving the CARE discount, on a cent per kWh basis.

d. DWR Bond Charge Revenue Requirement
The DWR Bond Charge revenue requirement shall be recovered based on the DWR Bond Charge authorized in the appropriate CPUC proceedings.

e. DA Cost Responsibility Surcharge (CRS) Undercollection
For the purpose of this Agreement, the full level of the CRS for DA customers is estimated to be 4.15 cents per kWh. Because the DA CRS is currently capped at 2.7 cents per kWh, the deficiency shall be allocated to bundled-service customers based on the "small" versus "large" customer allocation adopted in D. 03-07-030. This Agreement does not change the current methodology for allocation of this revenue deficiency.

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 Revenue Requirement
SCE's CPUC-jurisdictional Public Purpose Programs revenue requirement shall be allocated using the

current system average percent change (SAPC) method and shall be based upon all retail sales, including DA sales.

h. Trust Transfer Amount Revenue Requirement
The Trust Transfer Amount (TTA) revenue requirement is recovered through rates applicable to the residential and small commercial rate groups (the customers that received the 10 percent rate reduction implemented pursuant to Public Utilities Code Section 368). The rates that are designed to recover the principal and interest on the bonds that were used to finance the rate reduction are revised at least annually in accordance with a true-up mechanism approved in D. 97-09-056. Upon implementation of this Agreement, SCE shall include the currently-authorized TTA rates in the relevant residential and small commercial rate schedules.

i. CARE Balancing Account Revenue Requirement
The discount provided to CARE customers and any balance in the CARE Balancing Account shall be allocated to rate groups on an equal cents per kWh

basis including DA sales, but excluding the kWh usage of CARE and Streetlighting 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.

(2) <u>Current Consolidated Revenue Requirement</u>

In accordance with Advice Letter 1808-E and D. 04-07-022, SCE is currently authorized to recover annual revenues of $9,213,640,000.[3] However, in Advice Letter 1808-E, SCE did not establish Tier 3 (energy usage between 130% and 200% of baseline allocation) or Tier 4 rates (energy usage greater than 200% of baseline allocation) for residential CARE customers that were in excess of Tier 2 rates.[4] As a result, SCE's present rate revenues, based on rates effective August 5, 2004, are $9,196,535,000. The Phase 2 Revenue Allocation Agreement establishes revenue responsibility for each of SCE's rate groups. The combined total revenues to be recovered from bundled-service and DA customers are $9,192,200,000 (see discussion of capping, below).

(3) <u>Capping of Rate Group Revenue Responsibility</u>

The Commission has frequently adopted caps on the level of revenue responsibility allocated to rate groups in order to avoid harsh bill impacts while at the same time moving revenue responsibility towards the cost of service each rate

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[3] SCE AL 1808-E, p. 9, Table 5.

[4] Any undercollection of this amount is reflected in the CARE Balancing Account.

group imposes on SCE. For this proceeding, the Settling Parties agree to the following:

a. Bundled-Service Customers
Revenues assigned to each of the rate groups that receive bundled service from SCE shall not exceed the system average percentage change for bundled service customers plus four percent (SAPC + 4% Cap).[5]

b. Direct Access Customers
Revenues assigned to DA customers in each of the rate groups shall not exceed the system average percentage change for DA customers plus five percent (SAPC + 5% Cap).

(4) **<u>Allocation of Revenue Deficiency Due To Capping</u>**

a. Revenue Deficiency Due To Cap On Bundled-Service Rate Groups
The revenue deficiency created by the capping of the revenues allocated to the bundled-service customers under Paragraph 6.b)(3)a, above, shall be allocated to all other rate groups who are otherwise receiving revenue decreases. However, bundled-service customers in such rate groups, on average, shall receive no less than 40 percent of the revenue decrease the rate group otherwise would have received in the absence of any capping of the increased revenue responsibility to any bundled-service rate group. The

[5] Less than $2 million in revenues allocated to residential customers will be assigned by this Settlement Agreement to the GS-1 rate group so that Domestic rate group revenues will be capped at 3.5% above SAPC for bundled service and DA customers combined. SCE, CFBF and
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amount of the revenue reduction or the revenue increase to rate groups resulting from the capping of revenues allocated to bundled-service customers shall be allocated to SCE's distribution and generation rate components based on marginal distribution and generation cost revenues, respectively. DA customers only receive the benefit or detriment of capping with regard to the distribution rate component.

b. Revenue Deficiency Due To Cap On DA Rate Groups
Under the terms of this Agreement, the projected revenue deficiency of approximately $16 million created by the capping of revenues allocated to DA customers at SAPC plus 5% under Paragraph 6.b)(3)b, above, will not be reallocated to other DA or bundled-service customers. This revenue deficiency will be reflected in the appropriate SCE balancing accounts, for future amortization in rates. The benefit of this cap to the affected DA customers will be reflected in a ¢/kWh credit to those customers in order to maintain a uniform SCE delivery rate for both DA and bundled-service customers.

c) **Rate Design**

The Settling Parties agree that the results of the rate design process as shown by the rate levels in Appendix C to this Agreement ("Phase 2 Rate Design Agreement") are reasonable and should be adopted by the Commission.

Continued from the previous page
AECA also agreed to a slightly modified revenue allocation among the agricultural and pumping rate groups, which has no impact on the other rate groups.

(1) <u>Common Pricing Principles</u>

The following list of principles shall apply where relevant to all of SCE's rate schedules unless otherwise specifically excepted from such principles as part of this Agreement:

a. Customer Charges

   Customer charges shall be maintained at the levels established by Advice Letter 1808-E, as they were implemented on August 5, 2004.

b. Energy Charges

   1. Recovery of Delivery Costs

      i. For non-demand-metered rate schedules, all delivery costs, including but not limited to transmission, distribution, public purpose programs, nuclear decommissioning, as well as generation-related A&G costs, shall be recovered through seasonal or flat annual energy charges.

      ii. For demand-metered rate schedules, all delivery costs except transmission and distribution costs shall be recovered through energy charges. Transmission costs are recovered per authorized FERC rates while distribution costs (excluding generation A&G allocated to SCE's distribution revenue requirement) shall be allocated on a pro rata basis of 68% and 32% to non-coincident and coincident demands, respectively, of rate groups and shall be recovered through facilities-related and peak-demand related (seasonal or time-of- use (TOU)) demand charges.

2. Recovery of Generation-Related Costs
Generation-related costs, similar to delivery costs for non-demand metered rate schedules, shall be recovered through energy charges on SCE's rate schedules. For demand-metered rate schedules, generation-related costs shall be recovered through seasonal or TOU energy and demand charges. Total generation-related costs are divided into energy- and capacity-related components for recovery through energy and demand charges based on rates in effect prior to the addition of the energy surcharges in 2001. The energy component of the generation-related energy rate shall be divided between the DWR Power Charge and the URG rate component by first establishing the DWR Power Charge at the Commission-authorized cent per kilowatt hour rate for all rate schedules, and then determining the URG rate component on a residual basis.

c. Facilities-Related Demand Charges
For demand-metered rate schedules, a portion of generation capacity-related costs, 68% of distribution costs, as well as the FERC-authorized transmission charges, shall be recovered through facilities-related demand charges.

d. Peak Demand Charges

The remaining generation capacity-related costs, as defined above, as well as 32% of distribution costs shall be allocated to season or TOU period by the Loss of Load Probability method. These costs shall be recovered through seasonal or TOU demand charges.

e. Elimination of Ratchet Provision for Demand-Metered Rate Schedules

The Ratchet Provision, as used in the determination of billing demand for purposes of applying facilities-related demand charges for any of SCE's rate schedules, shall be eliminated upon the implementation of this Agreement.

f. All voltage discount provisions of applicable tariff schedules shall be modified to provide unit credits (per-kWh and per-kW) to the otherwise applicable rates for service delivered at higher voltages. Current voltage discounts apply percentage reductions to existing charges.

g. The use of the bill credit refund method to provide customer refunds for amounts accrued in the Electric Deferred Refund Account (EDRA) shall be limited to instances when the annual amount to be refunded exceeds $25 million. If the annual amount to be refunded does not meet this threshold value, SCE shall amortize the EDRA balance in future rates through an appropriate annual rate adjustment proceeding.

h. Other rate design proposals made by SCE in its initial testimony that were not opposed by other parties and were not altered in SCE's rebuttal testimony, and are not separately discussed herein, shall be incorporated in this Settlement Agreement.

(2) **<u>Residential Rate Group</u>**

a. Energy charges for SCE's Schedules D, D-CARE and other comparable residential rate schedules shall continue to reflect the current four 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; and over 200% of the baseline allocation, which is Tier 4.

b. In accordance with the Commission's interpretation of Water Code Section 80110, the Basic Charge and energy rates for usage up to 130% of the baseline allocation shall not be increased above the levels effective on January 4, 2001.

c. In order to implement the revenue increase to Schedule D-CARE consistent with the restrictions imposed by current law, and the Commission's interpretation thereof, Tier 1, Tier 2, and Tier 3 energy charges for Schedule D-CARE shall be established as follows: The Tier 1 rate shall increase by 1.0%; the Tier 2 rate shall increase by 7.0%; and the Tier 3 rate (determined residually to recover the capped revenue increase for CARE customers) shall be set at 13.8% above the current Tier 2 rate. To the extent SCE's budget for energy efficiency permits, SCE shall make a good faith effort to conduct energy efficiency audits of high energy usage CARE customers whose monthly usage appears to make them good candidates for applicable energy efficiency measures. Low-income group living facilities eligible to receive the CARE discount that are not served on residential rate schedules shall receive the same average discount from their otherwise applicable tariff as the discount received by customers on Schedule D- CARE. The balance of approximately $200,000 in the memorandum account established in accordance with D. 04-08-045 for nonresidential customers shall be transferred to the CARE Balancing Account upon implementation of this Settlement Agreement.

d. The discount provided to customers who provide submetered electric service and who are served on Schedule DMS-2 shall be $0.151 per space per day. This value reflects the current cost-of-service discount of $0.230 per space per day (adopted in D. 96-04-050) with a diversity adjustment of $0.100 per space per day, a Basic Charge adjustment of $-0.029 per space per day, and a combined adjustment for line losses and energy theft of $0.050 per space per day, which is the current adjustment. The diversity adjustment for Schedules DM and DMS-1 shall be $0.100 per space per day. In accordance with prior practice, the discount provided to customers served on Schedule DMS-1, shall be set a level that maintains the current ratio (28.6%) between the submetering discounts for

Schedules DMS-1 and DMS-2.[6] This discount for Schedule DMS-2 will be altered, if necessary, in accordance with Commission requirements for establishing the discount in Phase 2 of OII 03-03-018/OIR 03-03-017. Any other proposed tariff changes to Schedule DMS-2 shall not be implemented pending a Commission decision in Phase 2 of OII 03-03-018/OIR 03-03-017.

e. The minimum charge provisions for Domestic rate schedules shall be modified to eliminate minimum energy charges utilizing the base rates established in SCE's last GRC.

f. Schedule TOU-EV-2 shall be eliminated.

g. Schedule DE shall be retained, pending Commission resolution of employee discounts on a generic basis.

h. Pursuant to D. 04-02-057, baseline allowances shall continue in effect for residents of seasonal homes in zones 15 and 16, and the assessment of continued baseline allowances for seasonal residents shall be considered in SCE's 2006 GRC.

i. The distribution-related component of SCE's residential rates is currently adjusted between the summer and winter seasons to moderate and to levelize the impact of increased base rate revenues collected during the summer season from customer demand charges. The current seasonal rate adjustment in residential distribution rate components shall be

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6 D. 92-06-020, p. 138; D. 87-12-066, p. 299.

maintained for both bundled-service and DA customers.

j. All bill and rate limiter provisions shall be eliminated from rate schedules in the Domestic rate group.

k. The approximately 336 customer accounts located within the city of San Bernardino that are presently receiving the baseline allocation for zone 16 shall receive the baseline allocation provided to the majority of customer accounts in the city of San Bernardino, which is presently zone 17. This change shall be prospective only upon the Commission's approval of this Settlement Agreement, and the customers then receiving the baseline allocation for zone 17 shall not receive any adjustment to prior bills in which they received the baseline allocation for zone 16.

(3) <u>Agricultural and Pumping Rate Groups</u>

a. All bill and rate limiter provisions shall be eliminated from rate schedules in the Agricultural and Pumping rate groups.

b. The Pay-As-You-Grow Option, available to schedules in the Agricultural and Pumping rate groups, shall be maintained.

c. The applicability sections of the rate schedules in the Agricultural and Pumping rate groups shall not be modified.

d. PA-1 Rate Group

The current rate structure consisting of a customer charge, connected load per horsepower service charge, a flat energy charge, and off-peak credit shall be maintained. The off-peak credit shall be modified to include the distribution and generation components of the per-hp connected load charge.

e. PA-2 Rate Group
The components of the current rate structure consisting of a monthly customer charge, seasonal time-related demand charges, and a facilities-related demand charge shall be maintained. The current load-factor blocked energy charges shall be replaced by a flat energy charge that is differentiated between the summer and winter seasons.

f. Schedules TOU-PA-3, TOU-PA-4, and TOU-PA-6 shall be eliminated.

g. Schedule TOU-PA-7 rates shall be modified consistent with changes made to the underlying tariffs in accordance with this Agreement.

h. Schedule TOU-PA-SOP shall be retained and applied in conjunction with Schedule AP-I or TOU-BIP for interruptible load customers.

(4) **Large Power Rate Groups**

All components of the current rate structure, consisting of a monthly customer charge, facilities-related demand charge, and seasonal time-related demand charges and TOU energy charges shall be maintained.

a. Schedule I-6 shall be retained and revised to reflect an interruptible credit level of $78 per kW per year, differentiated by the applicable service voltage.

b. Optimal Billing Period (OBP) service shall be made permanent.

c. Schedules TOU-8-RTP, TOU-8-SOP-RTP, TOU-8-CR-1, and the Scheduled Load Reduction Program shall be eliminated.

d. All average and on-peak rate limiters shall be eliminated.

e. The interruptible bill limiter provision applicable to Schedule I-6 shall be eliminated.

f. Schedules RTP-2 and RTP-2-I shall be modified consistent with changes to the underlying tariff schedules. Interruptible credits reflected in hourly generation charges for Schedule RTP-2-I shall be reduced consistent with the same change under Schedule I-6.

g. Schedule I-6 Base Interruptible Program (BIP) shall be open to customers with demands in excess of 200 kW. The interruptible credit for Schedule I-6-BIP shall be applied to the average on-peak demand during the summer season and to the average mid-peak demand during the winter season. The excess energy penalty for failure to reduce load following notice of interruption shall be $10 per kWh of energy in excess of the customer's specified firm service level. A customer who fails to respond to two valid notices of interruption within a 12-month period shall be terminated from service on Schedule I-6-BIP.

h. A voluntary critical peak pricing tariff, known as CPP-GCCD (for Generation Capacity Charge Discount), based on ORA's recommendation shall be implemented for the TOU-8 rate groups. For this optional critical peak pricing tariff, generation capacity costs shall be recovered through the critical peak period energy charge. The critical peak pricing tariff proposed by SCE in R.02-06-001 on October 15, 2004 shall be referred to herein as the CPP-VCD (for Volumetric Charge Discount) tariff.

1. The CPP-GCCD tariff shall be triggered by a previously-specified temperature at the Los Angeles Civic Center or by ISO alerts. Each event will last from 12 p.m. until 6 p.m., with one energy price applying to the entire period. The CPP-GCCD tariff shall not be triggered more than 12 times in a calendar year. If during the course of a summer it seems likely that the CPP-GCCD will not be triggered 12 times, the temperature trigger can be adjusted downward so that the tariff can be expected to be triggered 12 times.
2. The revenue normally recovered through the generation component of the time-related demand charge shall be recovered through the critical peak energy charge under the CPP-GCCD tariff.
3. The CPP-GCCD tariff shall not be mandatory for any customers, including those customers served on SCE's interruptible load rate schedules.
4. Nothing in this Settlement Agreement shall alter or restrict the right of any party to propose or to argue in the pending Demand Response

OIR that customer participation in a critical peak pricing tariff should either be voluntary or mandatory.

(5) **Small and Medium Commercial Rate Group**

a. GS-1 Rate Group

For Schedule GS-1, the current rate structure consisting of a customer charge and an energy charge differentiated by summer and winter seasons shall be maintained. The bill limiter provision for customers formerly served on Schedule GS-1-PG shall be eliminated.

b. GS-2 Rate Group

For Schedule GS-2, the components of the current rate structure consisting of a monthly customer charge, seasonal time-related demand charges, and a facilities-related demand charge shall be maintained. The current load-factor blocked energy charges shall be replaced by a flat energy charge that is differentiated between the summer and winter seasons.

1. The TOU energy pricing option shall be maintained.
2. All customers with demand greater than 200 kW shall be required to take service on the TOU energy price option.
3. A TOU metering charge shall be added for customers selecting the TOU energy pricing options. Customers required to transfer to the TOU pricing option (based on the level of the

customer's peak demand) shall not be required to pay the TOU metering charge.

c. TOU-GS-2 Rate Group
For Schedule TOU-GS-2, the components of the current rate structure, consisting of a customer charge, a facilities-related demand charge, a seasonally- and TOU-differentiated demand charge, and seasonally- and TOU-differentiated energy charges shall be maintained.

d. Schedule TOU-GS-SOP-RTP shall be eliminated.

e. Schedules RTP-3 and RTP-3-GS shall be eliminated.

(6) <u>Street and Area Lighting Rate Group</u>

The current rate structure, consisting of monthly customer charges, energy charges for metered schedules, and per-lamp non-energy charges shall be maintained for all lighting schedules. The following changes shall be made:

a. Schedule AL-1 shall be eliminated.

b. Energy charges shall be modified to reflect allocated distribution and generation revenues as indicated in Appendix C of this Agreement.

c. The differential facilities rate proposed by SCE in its March 2003 update testimony (Exhibit SCE-16 Updated) should be adopted.

d. For all schedules in the Street and Area Lighting Rate Group, non-energy charges (including facilities charges and charges for TAP devices) shall be maintained at their current levels.

(7) <u>Traffic Control Rate Group</u>

The current rate structure, consisting of a daily customer (meter) charge and energy charges shall be maintained. The customer charge shall not change from the current levels. The amount of revenue allocated to the traffic control rate group shall be reflected in energy charges for the group.

(8) <u>Standby</u>

This Agreement shall establish a Standby rate schedule as a stand-alone rate schedule with charges for Supplemental, Backup and Maintenance rates with and without physical assurance. The Standby rate schedule shall provide for the following:

a. NGO metering is not necessary for existing standby customers (i.e., existing as of the date of a Commission decision approving this Settlement Agreement) with only Backup and Maintenance Demand (i.e., those customers who do not have Supplemental Demand because their generation capacity exceeds their total demand on the system).

b. NGO Metering is not necessary for standby customers who have Supplemental Demand where, at the election of the customer, the demand (kW) provided by SCE for Supplemental, Backup or Maintenance Power used in the calculation of the Maximum Demand shall be the recorded kW demand supplied by SCE as metered at the point of delivery (i.e., the "point of common coupling") to the customer premises. This customer election shall be subject to the following conditions:

   1. Existing Standby Customers

Customers receiving standby service from SCE as of the date of a final Commission decision approving this Agreement shall not be required to install utility NGO metering for billing purposes if they do not already have such meters. The Supplemental Contract Capacity and the Standby Reservation Contract Capacity shall be established in the Standby Service Agreement. However, the Standby Reservation Contract Capacity shall not exceed the nameplate capacity of the customer's generator. Excess Supplemental Demand shall be charged at the same rates that apply to the Supplemental Demand. Supplemental, Maintenance, and Backup Demands for existing standby customers shall be determined according to the following process:

i. Maintenance Demand shall be the kW of Maintenance Service scheduled by the customer with SCE.

ii. Excess Supplemental Demand shall be the metered kW demand, less the Supplemental Contract Capacity less the Standby Reservation Contract Capacity, less the Maintenance Demand, but not less than 0 kW.

iii. Supplemental Demand shall be the metered kW demand less the Excess Supplemental Demand and the

Maintenance Demand, but not less than 0 kW or greater than the Supplemental Contract Capacity.

iv. Backup Demand shall be the metered kW demand less the Excess Supplemental Demand less the Maintenance Demand less the Supplemental Demand, but not less than 0 kW.

2. New Standby Customers

Customers who begin receiving standby service from SCE as of the date of a final Commission decision approving this Settlement Agreement shall have an option to use the method of determining Supplemental, Maintenance, and Backup Demands described in Paragraph 6.c)(8)b.1., above, if they do not have NGO metering. This option will continue, pending a final and unappealable Commission decision in R.04-03-017 determining whether utility NGO metering is required. Nothing in this Settlement Agreement alters or restricts the right of any party to challenge such Commission decision in R.04-03-017 prior to it becoming final and unappealable. Once such decision is final and unappealable, SCE and these new standby customers will comply with that decision. If the Commission determines that NGO metering is required, the new standby customers will have NGO metering to determine Supplemental, Maintenance, and Backup Demands to calculate standby charges. If the Commission determines that NGO metering is not required, they will continue to have the option to use the method of determining Supplemental, Maintenance, and Backup Demands described in Paragraph 6.c)(8)b.1., above.

c. Standby Charges

   For the generation component of charges for Backup and Maintenance energy, customers served on SCE's Standby rate schedule shall have the choice of real-time energy prices when such prices are available, or a generation charge based on the weighted average of utility retained generation and DWR charges as shown in Appendix C.

d. Other standby rate design proposals that were either proposed by SCE or agreed to by SCE in its rebuttal testimony, and are not separately discussed herein, shall be incorporated in this Settlement Agreement.

e. In Phase 2 of SCE's 2006 GRC, SCE commits to further study of the effective demand factor (EDF) for standby customers and the use of EDFs in developing each rate group's cost responsibility for the distribution and subtransmission systems in the context of marginal cost allocation and rate design. In doing this, SCE will consider the relationship, if any, between the EDFs and SCE's distribution system planning.

f. In Decision 03-04-060, which was intended to fulfill certain requirements of Public Utilities Code

§353.13(a), the Commission extended on an interim basis the eligibility period for certain distributed generation (DG) customers to pay the same rates as customers with similar load profiles who do not install DG (i.e., remain on the customer's otherwise applicable tariff) with an exemption from the standby capacity reservation charge. DG customers who installed generation units as specified in D. 03-04-060 during the time periods specified in D. 03-04-060 would be exempt from standby charges until June 1, 2011. The Commission provided that eligibility for the exemption would be available to the specified types of DG units until a subsequent Commission decision revised each utility's rates applicable to standby customers consistent with the policies adopted in D. 01-07-027. The Commission also provided that the availability of the exemption would automatically be extended in six-month intervals beyond the dates specified in Ordering Paragraphs One and Two of D. 03-04-060 if the Commission had not yet revised each utility's rates applicable to standby customers. Based on these conditions, the following shall apply to existing and new DG customers:

1. Existing DG customers and new DG customers who have installed DG units of the type specified in D. 03-04-060 by December 31, 2004 shall remain eligible to receive the standby capacity reservation charge exemption and receive service

on the customer's otherwise applicable tariff through June 1, 2011.

2. Customers who install new DG units of the type specified in D. 03-04-060 between January 1, 2004 and the date rates are implemented in this proceeding shall remain eligible to receive the standby capacity reservation charge exemption and receive service on the customer's otherwise applicable tariff through June 1, 2011.
3. Customers who install new DG units of the type specified in D. 03-04-060 after the date rates are implemented in this proceeding shall choose one of two billing options, which shall be available on an interim basis until the Commission resolves the issues pending in OIR 04-03-017. Nothing in this Settlement Agreement alters or restricts the right of any party to challenge a Commission decision in OIR 04-03-017 prior to it becoming final and unappealable. When the Commission has issued a final and unappealable decision on the issues pending in OIR 04-03-017, the DG customers billed under either of the following two billing options, shall be billed prospectively based on outcome of that Commission decision:
    i. Interim DG Billing Option One
    Customers who install the specified DG units after the date rates are implemented in this proceeding may choose to be billed on an interim basis on the customer's

otherwise applicable tariff, and be exempt from paying the standby capacity reservation charge.

ii. Interim DG Billing Option Two
Customers who install the specified DG units after the date rates are implemented in this proceeding may choose to be billed on an interim basis on the revised standby rates adopted in this proceeding, without exemption from paying the standby capacity reservation charge.

g. The applicability of the standby rates and terms specified in this Settlement Agreement to the eligible DG customers referred to in Paragraph 6.c)(8)f., above, shall be subject to change as a result of a subsequent Commission decision in the DG OIR (Rulemaking 04-03-017).

7. **Implementation of Agreement**

SCE's current consolidated revenue requirement (effective with D. 04-07-022 and Advice Letter 1808-E) shall be implemented in accordance with the principles and specific terms of this Agreement. Any other revenue requirement change adopted by the Commission prior to the implementation of SCE's 2006 GRC Phase 2 decision shall be implemented on an SAPC basis by function. SCE will implement the rates resulting from this Agreement as soon as practicable following the issuance of a final Commission decision approving this Agreement.

8. 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.

9. Signature Date

This Agreement shall become binding on the signature date.

10. 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.

11. 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.

12. Non Precedent

Consistent with Rule 51.8 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.

13. 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.

14. 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.

15. Effect Of Subject Headings

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

16. 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.

17. 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: Bruce A Reed

Title: Senior Attorney

OFFICE OF RATEPAYER ADVOCATES

By:

Title:

THE UTILITY REFORM NETWORK

By:

Title:

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: ______________________

Title: ______________________

OFFICE OF RATEPAYER ADVOCATES

By: ______________________

Title: Counsel for ORA

THE UTILITY REFORM NETWORK

By: ______________________

Title: ______________________

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: ______________________

Title: ______________________

OFFICE OF RATEPAYER ADVOCATES

By: ______________________

Title: ______________________

THE UTILITY REFORM NETWORK

By: Marcel Hawiger

Title: Staff Attorney

CALIFORNIA FARM BUREAU FEDERATION

By: _______________

Title: Associate Counsel

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

By: _______________

Title: _______________

FEDERAL EXECUTIVE AGENCIES

By: _______________

Title: _______________

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: _______________

Title: _______________

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: _______________

Title: _______________

INDICATED COMMERCIAL PARTIES

By: _______________

Title: _______________

CALIFORNIA FARM BUREAU FEDERATION

By: ______________________________

Title: ______________________________

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

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Title: Executive Director

FEDERAL EXECUTIVE AGENCIES

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Title: ______________________________

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Title: ______________________________

INDICATED COMMERCIAL PARTIES

By: ______________________________

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CALIFORNIA FARM BUREAU FEDERATION

By: ________________________________

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AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

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FEDERAL EXECUTIVE AGENCIES

By: Norman Furuta

NORMAN FURUTA

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INDICATED COMMERCIAL PARTIES

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Title: ______________________________

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

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FEDERAL EXECUTIVE AGENCIES

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FEDERAL EXECUTIVE AGENCIES

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CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

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INDICATED COMMERCIAL PARTIES

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Title: Manatt, Phelps & Phillips, LLP
Attorneys for Indicated Commercial Parties

JOINT PARTIES INTERESTED IN DISTRIBUTED GENERATION/DISTRIBUTED ENERGY RESOURCES

By: Ann L. Trowbridge

Title: Counsel to the Joint Parties

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By:

Title:

NATURAL RESOURCES DEFENSE COUNCIL

By:

Title:

WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

By:

Title:

JOINT PARTIES INTERESTED IN DISTRIBUTED GENERATION/DISTRIBUTED ENERGY RESOURCES

By: ____________________

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By: Reed V. Schmidt

Title: Energy Economist

NATURAL RESOURCES DEFENSE COUNCIL

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Title: ______________________

NATURAL RESOURCES DEFENSE COUNCIL

By: Sheryl Carter

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WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

By: ______________________

Title: ______________________

JOINT PARTIES INTERESTED IN DISTRIBUTED GENERATION/DISTRIBUTED ENERGY RESOURCES

By: ______________________

Title: ______________________

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: ______________________

Title: ______________________

NATURAL RESOURCES DEFENSE COUNCIL

By: ______________________

Title: ______________________

WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

By: ______________________

Title: Counsel for WMA

COGENERATION ASSOCIATION OF CALIFORNIA
AND ENERGY PRODUCERS AND USERS
COALITION

By: [signature]

Title: Counsel

MANFRED GILDNER

By: ____________________

Title: ____________________

COGENERATION ASSOCIATION OF CALIFORNIA
AND ENERGY PRODUCERS AND USERS
COALITION

By: ______________________

Title: ______________________

MANFRED GILDNER

By: Manfred F. Gildner

Title: RATEPAYER

Appendix A

Comparison of ORA, SCE and Settlement Revenue Allocation

SCE Phase 2 Settlement Agreement
Bundled Service Rate Comparison (c/kWh)

	Current Average Rate	ORA [1] Table 2-2 (Adjusted for Phase 1 Bundled Revenue Req)	ORA [1] % change	SCE Rebuttal [2] (Adjusted for Phase 1 Bundled Revenue Req)	SCE Rebuttal [2] % change	Settlement [3] Appendix B	Settlement [3] % change
Residential	12.547	13.524	7.8%	13.819	10.1%	13.012	3.7%
GS-1	15.172	13.490	-11.1%	13.656	-10.0%	14.383	-5.2%
TC-1	12.149	10.160	-16.4%	9.610	-20.9%	11.192	-7.9%
GS-2	13.141	12.010	-8.6%	12.125	-7.7%	12.799	-2.6%
TOU-GS-2	12.796	10.185	-20.4%	9.453	-26.1%	10.169	-20.5%
LSMP	13.494	12.226	-9.4%	12.328	-8.6%	13.015	-3.6%
TOU-8-Sec	11.092	10.729	-3.3%	10.649	-4.0%	10.992	-0.9%
TOU-8-Pri	10.353	10.843	4.7%	9.759	-5.7%	10.147	-2.0%
TOU-8-Sub	7.541	8.021	6.4%	7.381	-2.1%	7.493	-0.6%
Large Power	10.015	10.112	1.0%	9.594	-4.2%	9.895	-1.2%
PA-1	14.394	12.078	-16.1%	11.742	-18.4%	13.716	-4.7%
PA-2	10.231	9.780	-4.4%	9.371	-8.4%	9.962	-2.6%
AG-TOU	8.408	10.308	22.6%	9.719	15.6%	8.576	2.0%
TOU-PA-5	8.150	9.907	21.6%	9.661	18.5%	8.313	2.0%
Ag.&Pumping	9.383	10.342	10.2%	9.934	5.9%	9.375	-0.1%
St.Lighting	15.215	15.631	2.7%	14.008	-7.9%	14.043	-7.7%
System [4]	12.215	12.187	-0.2%	12.187	-0.2%	12.178	-0.3%

[1] ORA rebuttal testimony, Revenue Allocation, Page 2-2, adjusted to conform to Settlement Agreement revenue requirement.

[2] SCE rebuttal position, adjusted to conform to Settlement Agreement revenue requirement.

[3] Settlement average rates include capping and reallocation of revenue increases among rate groups based on the criteria established by the Settling Parties. While both ORA and SCE proposed or supported capping in their rebuttal testimonies, neither proposed reallocation principles. Capping is not reflected in the ORA or SCE class average rates shown here.

[4] The reduction in the total bundled service rate in the Settlement Agreement versus the ORA and SCE positions reflects a distribution credit to certain DA customers pursuant to the Settlement Agreement.

Appendix B

Phase 2 Revenue Allocation Agreement

Settlement Agreement Allocated Revenues
For Customer Groups
Bundled Service, Direct Access Service, and Combined Retail

2003 GRC Phase 2 Revenue Allocation Agreement

Revenues in $MM
Bundled Service: SAPC +4% Cap, 40% Secondary Cap Limit
Direct Access: SAPC +5% Cap

		Bundled Service						DA Service						Retail Service				
Rate Schedule by Customer Group	Bundled GWh Sales	Current Revenue	Allocated Revenue (no caps)	% Change	Settlement Allocated Revenue (with caps)	% Change	DA GWh Sales	Current Revenue	Allocated Revenue (no caps)	% Change	Settlement Allocated Revenue (with caps)	% Change	Retail GWh Sales	Current Revenue	Allocated Revenue (no caps)	% Change	Settlement Allocated Revenue (with caps)	% Change
Domestic																		
CARE	4,831.5	438.8	472.5	7.68%	455.0	3.70%	26.8	1.098	1.000	-8.91%	0.967	-11.92%	4,858.3	439.9	473.5	7.63%	456.0	3.66%
NON-CARE	21,153.1	2,821.6	3,070.0	8.80%	2,926.0	3.70%	218.4	21.5	21.7	0.80%	21.2	-1.57%	21,371.4	2,843.1	3,091.7	8.74%	2,947.2	3.66%
Group Total	25,984.6	3,260.4	3,542.4	8.65%	3,381.0	3.70%	245.2	22.6	22.7	0.33%	22.2	-2.07%	26,229.7	3,283.0	3,565.2	8.59%	3,403.2	3.66%
Lighting-SM Med Power																		
GS-1	4,514.3	684.9	610.1	-10.92%	649.3	-5.20%	86.3	9.0	7.6	-15.22%	7.8	-13.03%	4,600.5	693.9	617.7	-10.98%	657.1	-5.30%
TC-1	74.1	9.0	7.8	-13.36%	8.3	-7.88%	1.8	0.1	0.1	8.23%	0.1	11.16%	75.9	9.1	7.9	-13.07%	8.4	-7.63%
GS-2	19,960.1	2,623.0	2,452.2	-6.51%	2,554.7	-2.60%	3,080.6	193.5	230.2	18.99%	216.0	11.64%	23,040.6	2,816.4	2,682.4	-4.76%	2,770.7	-1.63%
TOU-GS-2	608.4	77.9	58.2	-25.19%	61.9	-20.53%	74.5	5.3	4.4	-15.54%	4.5	-13.60%	683.0	83.1	62.7	-24.58%	66.4	-20.09%
Group Total	25,156.8	3,394.7	3,128.4	-7.85%	3,274.1	-3.55%	3,243.2	207.9	242.4	16.63%	228.5	9.93%	28,400.0	3,602.6	3,370.8	-6.43%	3,502.6	-2.77%
Large Power																		
TOU-8-SEC	7,125.1	790.3	772.4	-2.26%	783.2	-0.91%	1,878.5	118.4	121.3	2.49%	122.1	3.14%	9,003.6	908.7	893.8	-1.65%	905.3	-0.38%
TOU-8-PRI	4,695.6	486.1	462.0	-4.97%	476.5	-1.99%	1,670.4	99.8	96.8	-3.02%	98.1	-1.71%	6,366.0	586.0	558.8	-4.64%	574.6	-1.94%
TOU-8-SUB	3,747.4	282.6	278.1	-1.61%	280.8	-0.64%	4,098.0	157.6	156.2	-0.86%	156.6	-0.64%	7,845.5	440.2	434.3	-1.34%	437.4	-0.64%
Group Total	15,568.1	1,559.1	1,512.5	-2.99%	1,540.4	-1.20%	7,647.0	375.8	374.4	-0.38%	376.8	0.27%	23,215.1	1,934.9	1,886.9	-2.48%	1,917.3	-0.91%
Agricultural & Pumping																		
PA-1	411.4	59.2	50.1	-15.43%	56.4	-4.71%	4.7	0.3	0.4	9.52%	0.4	11.64%	416.1	59.5	50.4	-15.29%	56.8	-4.62%
PA-2	383.8	39.3	36.7	-6.57%	38.2	-2.63%	21.9	1.3	1.3	2.28%	1.3	3.69%	405.7	40.5	38.0	-6.30%	39.5	-2.43%
TOU-AG	1,108.6	93.2	108.3	16.23%	95.1	2.00%	51.6	3.1	3.3	8.68%	3.2	3.99%	1,160.2	96.3	111.7	15.99%	98.3	2.06%
TOU-PA-5	1,059.3	86.3	103.8	20.29%	88.1	2.00%	6.8	0.3	0.4	28.39%	0.4	11.64%	1,066.1	86.7	104.3	20.32%	88.4	2.04%
Group Total	2,963.2	278.0	299.0	7.53%	277.8	-0.08%	85.0	5.0	5.4	8.40%	5.2	4.91%	3,048.2	283.0	304.3	7.54%	283.0	0.00%
Street & Area Lighting	604.0	91.9	82.6	-10.16%	84.8	-7.71%	13.7	1.2	1.6	34.54%	1.3	11.64%	617.7	93.1	84.2	-9.59%	86.2	-7.46%
Grand Total	70,276.7	8,584.1	8,564.8	-0.22%	8,558.2	-0.30%	11,234.1	612.5	646.6	5.56%	634.0	3.52%	81,510.7	9,196.6	9,211.3	0.16%	9,192.2	-0.05%

Settlement Agreement Allocated Revenues
Average Rates For Customer Groups
Bundled Service, Direct Access Service, and Combined Retail

2003 GRC Phase 2 Revenue Allocation Agreement

Rates shown in cents/kWh
Bundled Service: SAPC +4% Cap, 40% Secondary Cap Limit
Direct Access: SAPC +5% Cap

Rate Schedule by Customer Group	Bundled GWh Sales	Bundled Service Current Rate	Bundled Service Uncapped Rate	Bundled Service % Change	Settlement Capped Rate	% Change	DA GWh Sales	DA Service Current Rate	DA Service Uncapped Rate	DA Service % Change	Settlement Capped Rate	% Change	Retail GWh Sales	Retail Service Current Rate	Retail Service Uncapped Rate	Retail Service % Change	Settlement Capped Rate	% Change
Domestic																		
CARE	4,831.5	9.082	9.779	7.68%	9.418	3.70%	26.8	4.098	3.732	-8.91%	3.609	-11.92%	4,858.3	9.055	9.746	7.63%	9.386	3.66%
NON-CARE	21,153.1	13.339	14.513	8.80%	13.832	3.70%	218.4	9.867	9.946	0.80%	9.713	-1.57%	21,371.4	13.303	14.466	8.74%	13.790	3.66%
Group Total	25,984.6	12.547	13.633	8.65%	13.012	3.70%	245.2	9.237	9.267	0.33%	9.046	-2.07%	26,229.7	12.516	13.592	8.59%	12.975	3.66%
Lighting-SM Med Power																		
GS-1	4,514.3	15.172	13.515	-10.92%	14.383	-5.20%	86.3	10.444	8.854	-15.22%	9.083	-13.03%	4,600.5	15.083	13.428	-10.98%	14.284	-5.30%
TC-1	74.1	12.149	10.526	-13.36%	11.192	-7.88%	1.8	6.638	7.185	8.23%	7.379	11.16%	75.9	12.016	10.445	-13.07%	11.100	-7.63%
GS-2	19,960.1	13.141	12.286	-6.51%	12.799	-2.60%	3,080.6	6.281	7.474	18.99%	7.012	11.64%	23,040.6	12.224	11.642	-4.76%	12.025	-1.63%
TOU-GS-2	608.4	12.796	9.572	-25.19%	10.169	-20.53%	74.5	7.052	5.956	-15.54%	6.092	-13.60%	683.0	12.169	9.178	-24.58%	9.724	-20.09%
Group Total	25,156.8	13.494	12.435	-7.85%	13.015	-3.55%	3,243.2	6.410	7.476	16.63%	7.046	9.93%	28,400.0	12.685	11.869	-6.43%	12.333	-2.77%
Large Power																		
TOU-8-SEC	7,125.1	11.092	10.841	-2.26%	10.992	-0.91%	1,878.5	6.301	6.458	2.49%	6.499	3.14%	9,003.6	10.093	9.927	-1.65%	10.054	-0.38%
TOU-8-PRI	4,695.6	10.353	9.839	-4.97%	10.147	-1.99%	1,670.4	5.977	5.797	-3.02%	5.875	-1.71%	6,366.0	9.205	8.778	-4.64%	9.026	-1.94%
TOU-8-SUB	3,747.4	7.541	7.420	-1.61%	7.493	-0.64%	4,098.0	3.846	3.813	-0.86%	3.821	-0.64%	7,845.5	5.611	5.536	-1.34%	5.575	-0.64%
Group Total	15,568.1	10.015	9.715	-2.99%	9.895	-1.20%	7,647.0	4.915	4.896	-0.38%	4.928	0.27%	23,215.1	8.335	8.128	-2.48%	8.259	-0.91%
Agricultural & Pumping																		
PA-1	411.4	14.394	12.173	-15.43%	13.716	-4.71%	4.7	6.851	7.504	9.52%	7.648	11.64%	416.1	14.309	12.121	-15.29%	13.647	-4.62%
PA-2	383.8	10.231	9.559	-6.57%	9.962	-2.63%	21.9	5.717	5.847	2.28%	5.927	3.69%	405.7	9.987	9.358	-6.30%	9.744	-2.43%
TOU-AG	1,108.6	8.408	9.773	16.23%	8.576	2.00%	51.6	5.933	6.448	8.68%	6.170	3.99%	1,160.2	8.298	9.625	15.99%	8.469	2.06%
TOU-PA-5	1,059.3	8.150	9.803	20.29%	8.313	2.00%	6.8	4.759	6.111	28.39%	5.313	11.64%	1,066.1	8.128	9.779	20.32%	8.293	2.04%
Group Total	2,963.2	9.383	10.089	7.53%	9.375	-0.08%	85.0	5.834	6.324	8.40%	6.121	4.91%	3,048.2	9.284	9.984	7.54%	9.284	0.00%
Street & Area Lighting	604.0	15.215	13.669	-10.16%	14.043	-7.71%	13.7	8.739	11.758	34.54%	9.756	11.64%	617.7	15.071	13.626	-9.59%	13.948	-7.46%
Grand Total	70,276.7	12.215	12.187	-0.22%	12.178	-0.30%	11,234.1	5.452	5.755	5.56%	5.644	3.52%	81,510.7	11.283	11.301	0.16%	11.277	-0.05%

Appendix C

Phase 2 Rate Design Agreement

Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
D						
Energy Charge- $/kWh						
Baseline - Summer	0.11808	0.11808	0.00000	0.00%	0.04432	0.04067
- Winter	0.11808	0.11808	0.00000	0.00%	0.09737	0.08522
101% - 130% of Baseline - Summer	0.13741	0.13741	0.00000	0.00%	0.04432	0.04280
- Winter	0.13741	0.13741	0.00000	0.00%	0.09737	0.09401
131% - 200% of Baseline - Summer	0.15530	0.16596	0.01066	6.87%	0.04432	0.04619
- Winter	0.15530	0.16596	0.01066	6.86%	0.09737	0.10797
Over 200% of Baseline	0.16928	0.19346	0.02418	14.28%	0.04432	0.04934
- Winter	0.16928	0.19346	0.02418	14.28%	0.09737	0.12095
Basic Charge - $/day						
Single-Family Residence	0.029	0.029	0.000	0.00%	0.029	0.029
Multi-Family Residence	0.022	0.022	0.000	0.00%	0.022	0.022
Minimum Charge - $/day						
Single Family Residence	0.059	0.059	0.000	0.00%	0.059	0.059
Multi-Family Residence	0.044	0.044	0.000	0.00%	0.044	0.044
D-CARE						
Energy Charge - $/kWh						
Baseline - Summer	0.08530	0.08615	0.00085	1.00%	0.01203	0.00144
- Winter	0.08530	0.08615	0.00085	1.00%	0.06509	0.04883
101% - 130% of Baseline - Summer	0.10065	0.10771	0.00706	7.01%	0.00805	0.00501
- Winter	0.10065	0.10771	0.00706	7.01%	0.06111	0.06355
131% - 200% of Baseline - Summer	0.10066	0.11457	0.01391	13.82%	(0.00822)	0.00616
- Winter	0.10066	0.11457	0.01391	13.82%	0.04484	0.06826
Over 200% of Baseline	0.10066	0.11457	0.01391	13.82%	(0.02580)	0.00616
- Winter	0.10066	0.11457	0.01391	13.82%	0.02726	0.06826
Basic Charge - $/day						
Single-Family Residence	0.023	0.023	0.000	0.00%	0.023	0.023
Multi-Family Residence	0.017	0.017	0.000	0.00%	0.017	0.017
Minimum Charge - $/day						
Single Family Residence	0.047	0.047	0.000	0.00%	0.047	0.047
Multi-Family Residence	0.034	0.034	0.000	0.00%	0.034	0.034
DE						
DE Discount - %	25.00%	25.00%	0.00	0.00%		
DM						
Diversity Adjustment - $/unit/day	0.018	0.100	0.082	455.56%	0.000	0.100
Agricultural Employee Housing Discount - %	20.00%	CARE Average				
DMS-1						
Submeter Discount - $/unit/day	(0.080)	(0.080)	0.000	0.00%	(0.080)	(0.080)
Diversity Adjustment - $/unit/day	0.018	0.100	0.082	455.56%	0.000	0.100
Basic Charge - $/unit/day	0.022	0.029	0.007	31.82%	0.022	0.029
Minimum Average Rate - $/kWh	0.02707	0.02235	(0.00472)	-17.44%	0.00000	0.02235
DMS-2						
Submeter Discount - $/unit/day	(0.280)	(0.280)	0.000	0.00%	(0.280)	(0.280)
Diversity Adjustment - $/unit/day	0.009	0.100	0.091	1011.11%	0.000	0.100
Basic Charge - $/unit/day	0.022	0.029	0.007	31.82%	0.022	0.029
Minimum Average Rate - $/kWh	0.02707	0.02235	(0.00472)	-17.44%	0.00000	0.02235
DMS-3						
Basic Charge Adjust - $/unit/day	0.022	0.029	0.007	31.82%	0.022	0.029
DS						
Summer Season Premium - $/kWh/day	0.070	0.070	0.000	0.00%	0.030	0.030
Winter Season Discount - $/kWh/day	(0.070)	(0.070)	0.000	0.00%	(0.030)	(0.030)
California Alternate Rates for Energy Discount - %	100.00	100.00	0.00	0.00%	100.00	100.00

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		Total Bundled Rate				Total Delivery Rate	
		Current	Proposed	Difference	% Diff	Current	Proposed
TOU-D-1							
Energy Charge - $/kWh							
	Summer Season - On-Peak	0.30710	0.31846	0.01136	3.70%	0.07886	0.07444
	Off-Peak	0.12673	0.13142	0.00469	3.70%	0.07886	0.07444
	Winter Season - On-Peak	0.14390	0.14922	0.00532	3.70%	0.07886	0.07444
	Off-Peak	0.12042	0.12488	0.00446	3.70%	0.07886	0.07444
Basic Charge - $/day							
	Single-Family Residence	0.029	0.029	0.000	0.00%	0.029	0.029
	Multi-Family Residence	0.022	0.022	0.000	0.00%	0.022	0.022
TOU Meter Charge - $/day		0.09	0.09	0.00	0.00%	0.09	0.09
Minimum Charge - $/day							
	Single Family Residence	0.059	0.059	0.000	0.00%	0.059	0.059
	Multi-Family Residence	0.044	0.044	0.000	0.00%	0.044	0.044
Baseline Credit - $/kWh		(0.01717)	(0.01717)	0.00000	0.00%	(0.00625)	(0.00625)
TOU-D-2							
Energy Charge - $/kWh							
	Summer Season - On-Peak	0.25992	0.26954	0.00962	3.70%	0.07865	0.07444
	Off-Peak	0.11693	0.12126	0.00433	3.70%	0.07865	0.07444
	Winter Season - On-Peak	0.13030	0.13512	0.00482	3.70%	0.07865	0.07444
	Off-Peak	0.11177	0.11591	0.00414	3.70%	0.07865	0.07444
Customer Charge - $/day		0.23	0.23	0.00	0.00%	0.13	0.23
TOU Meter Charge - $/day		0.09	0.09	0.00	0.00%	0.09	0.09
TOU-EV-1							
Energy Charge - $/kWh							
	Summer Season - On-Peak	0.23109	0.23964	0.00855	3.70%	0.13370	0.07444
	Off-Peak	0.08060	0.08358	0.00298	3.70%	0.06609	0.07444
	Winter Season - On-Peak	0.10824	0.11224	0.00400	3.70%	0.06853	0.07444
	Off-Peak	0.08184	0.08487	0.00303	3.70%	0.06315	0.07444
TOU Meter Charge - $/day		0.14	0.14	0.00	0.00%	0.14	0.14
Minimum Charge - $/day		0.15	0.15	0.00	0.00%	0.15	0.15
D-APS							
Air Conditioning Cycling Credit - $/ton/summer season day							
	50% Cycling	(0.05)	(0.05)	0.00	0.00%	(0.05)	(0.05)
	67% Cycling	(0.10)	(0.10)	0.00	0.00%	(0.10)	(0.10)
	100% Cycling	(0.18)	(0.18)	0.00	0.00%	(0.18)	(0.18)
D-APS-E							
Air Conditioning Cycling Credit - $/ton/summer season day							
	50% Cycling	(0.10)	(0.10)	0.00	0.00%	(0.10)	(0.10)
	67% Cycling	(0.20)	(0.20)	0.00	0.00%	(0.20)	(0.20)
	100% Cycling	(0.36)	(0.36)	0.00	0.00%	(0.36)	(0.36)
GS-1							
Energy Charge - $/kWh							
	Summer	0.15343	0.14549	(0.00794)	-5.17%	0.06938	0.05032
	Winter	0.12313	0.11304	(0.01009)	-8.19%	0.06938	0.05032
Customer Charge - $/day		0.50	0.50	0.00	0.00%	0.40	0.50
Three Phase Service - $/day		0.071	0.083	0.012	16.90%	0.071	0.083
TOU Option Meter Charge - $/day			0.35	0.35			0.35
Voltage Discount, or Surcharge Energy - $/kWh							
	From 2 kV to 50 kV		(0.00172)	(0.00172)			(0.00066)
	Above 50 kV		(0.02425)	(0.02425)			(0.02197)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-EV-3						
Energy Charge - $/kWh						
Summer Season On-Peak	0.23554	0.22330	(0.01224)	-5.20%	0.11858	0.05032
Off-Peak	0.08949	0.08484	(0.00465)	-5.20%	0.05996	0.05032
Winter Season On-Peak	0.10701	0.10145	(0.00556)	-5.20%	0.06143	0.05032
Off-Peak	0.08981	0.08514	(0.00467)	-5.20%	0.05758	0.05032
Customer Charge - $/day	0.56	0.56	0.00	0.00%	0.40	0.56
TOU Meter Charge - $/day	0.14	0.14	0.00	0.00%	0.14	0.14
TOU-GS-1						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.30610	0.29019	(0.01591)	-5.20%	0.06962	0.05032
Mid-peak	0.11551	0.10951	(0.00600)	-5.19%	0.06962	0.05032
Off-Peak	0.10142	0.09615	(0.00527)	-5.20%	0.06962	0.05032
Winter Season						
Mid-peak	0.11252	0.10667	(0.00585)	-5.20%	0.06962	0.05032
Off-Peak	0.10116	0.09590	(0.00526)	-5.20%	0.06962	0.05032
Customer Charge - $/day	0.50	0.50	0.00	0.00%	0.40	0.50
TOU Meter Charge - $/day	0.09	0.09	0.00	0.00%	0.09	0.09
Three-Phase Service - $/day	0.071	0.083	0.012	16.90%	0.071	0.083
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00172)	(0.00172)			(0.00066)
Above 50 kV		(0.02425)	(0.02425)			(0.02197)
GS-APS (Schedules: GS-1 and TOU-GS-1)						
Air Conditioning Cycling Credit - $/ton/summer season day						
30% Cycling	(0.014)	(0.014)	0.000	0.00%	(0.014)	(0.014)
40% Cycling	(0.042)	(0.042)	0.000	0.00%	(0.042)	(0.042)
50% Cycling	(0.070)	(0.070)	0.000	0.00%	(0.070)	(0.070)
100% Cycling	(0.200)	(0.200)	0.000	0.00%	(0.200)	(0.200)
GS-APS-E (Schedules: GS-1 and TOU-GS-1)						
Air Conditioning Cycling Credit - $/ton/summer season day						
30% Cycling	(0.028)	(0.028)	0.000	0.00%	(0.028)	(0.028)
40% Cycling	(0.084)	(0.084)	0.000	0.00%	(0.084)	(0.084)
50% Cycling	(0.140)	(0.140)	0.000	0.00%	(0.140)	(0.140)
100% Cycling	(0.400)	(0.400)	0.000	0.00%	(0.400)	(0.400)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
GS-2						
Energy Charge - $/kWh						
Summer	0.09283	0.08035	(0.01248)	-13.44%	0.01897	0.02029
Winter	0.10193	0.07789	(0.02404)	-23.58%	0.01897	0.02029
Time-of-use Pricing Option Energy Charge - $/kWh						
Summer Season						
On-Peak	0.12796	0.11782	(0.01014)	-7.92%	0.01897	0.02029
Mid-peak	0.09435	0.08070	(0.01365)	-14.47%	0.01897	0.02029
Off-Peak	0.08484	0.05756	(0.02728)	-32.15%	0.01897	0.02029
Winter Season						
Mid-peak	0.09922	0.09500	(0.00422)	-4.25%	0.01897	0.02029
Off-Peak	0.08484	0.05878	(0.02606)	-30.72%	0.01897	0.02029
Customer Charge - $/month	74.03	74.03	0.00	0.00%	67.78	74.03
Single Phase Service - $/month	(2.40)	(2.95)	(0.55)	22.92%	(2.40)	(2.95)
Facilities Related Demand Charge - $/kW	6.21	8.63	2.42	38.97%	5.44	6.19
Summer Time Related Demand Charge - $/kW	8.91	13.89	4.98	55.89%	7.04	7.95
TOU Option Meter Charge - $/month						
Standard		13.44	13.44			13.44
TOU-RTEM		47.90	47.90			47.90
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00076)	(0.00076)			0.00000
Above 50 kV		(0.00164)	(0.00164)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.14)	(0.14)			(0.11)
Above 50 kV		(3.80)	(3.80)			(3.72)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.26)	(0.26)			(0.18)
Above 50 kV		(6.21)	(6.21)			(6.01)
TOU-GS-2 (Option A)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.23051	0.22385	(0.00666)	-2.89%	0.09106	0.06247
Mid-peak	0.08946	0.07381	(0.01565)	-17.49%	0.02190	0.01893
Off-Peak	0.07718	0.05246	(0.02472)	-32.03%	0.02190	0.01893
Winter Season						
Mid-peak	0.09574	0.08473	(0.01101)	-11.50%	0.02190	0.01893
Off-Peak	0.07718	0.05246	(0.02472)	-32.03%	0.02190	0.01893
Customer Charge - $/month	89.65	89.65	0.00	0.00%	67.78	89.65
Facilities Related						
Demand Charge - $/kW	6.12	4.42	(1.70)	-27.78%	5.00	3.03
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	8.94	6.74	(2.20)	-24.61%	7.10	4.56
Mid-Peak	2.45	2.31	(0.14)	-5.71%	1.21	0.85
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00

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Phase 2 Rate Design Agreement
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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-GS-2 (Option B)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.13556	0.14483	0.00927	6.84%	0.02023	0.01781
Mid-peak	0.08556	0.07125	(0.01431)	-16.73%	0.02023	0.01781
Off-Peak	0.07328	0.05044	(0.02284)	-31.17%	0.02023	0.01781
Winter Season						
Mid-peak	0.09184	0.08189	(0.00995)	-10.83%	0.02023	0.01781
Off-Peak	0.07328	0.05044	(0.02284)	-31.17%	0.02023	0.01781
Customer Charge - $/month	89.65	89.65	0.00	0.00%	67.78	89.65
Facilities Related						
Demand Charge - $/kW	6.12	4.42	(1.70)	-27.78%	5.00	3.03
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	18.61	14.26	(4.35)	-23.37%	14.18	8.77
Mid-Peak	2.45	2.29	(0.16)	-6.53%	1.21	0.75
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-GS-2 (Both Options)						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01000)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04000)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00069)	(0.00069)			0.00000
Above 50 kV		(0.00148)	(0.00148)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.08)	(0.08)			(0.06)
Above 50 kV		(2.07)	(2.07)			(2.02)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.15)	(0.15)			(0.10)
Above 50 kV		(3.38)	(3.38)			(3.26)
TOU-GS-2-SOP						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.13479	0.11404	(0.02075)	-15.39%	0.02239	0.01948
Mid-peak	0.10007	0.08483	(0.01524)	-15.23%	0.02239	0.01948
Super Off-Peak	0.07558	0.06423	(0.01135)	-15.02%	0.02239	0.01948
Winter Season						
Mid-peak	0.10053	0.08522	(0.01531)	-15.23%	0.02239	0.01948
Super Off-Peak	0.07558	0.06423	(0.01135)	-15.02%	0.02239	0.01948
Customer Charge - $/month	89.65	89.65	0.00	0.00%	67.78	89.65
Facilities Related						
Demand Charge - $/kW	6.12	4.42	(1.70)	-27.78%	5.01	3.03
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	41.66	31.98	(9.68)	-23.24%	16.98	11.22
Mid-peak	1.22	0.89	(0.33)	-27.05%	0.76	0.50
Winter Season						
Mid-peak	0.66	0.45	(0.21)	-31.82%	0.58	0.38
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00069)	(0.00069)			0.00000
Above 50 kV		(0.00148)	(0.00148)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.08)	(0.08)			(0.06)
Above 50 kV		(2.07)	(2.07)			(2.02)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.15)	(0.15)			(0.10)
Above 50 kV		(3.38)	(3.38)			(3.26)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-EV-4						
Energy Charge - $/kWh						
Summer Season On-Peak	0.10987	0.09328	(0.01659)	-15.10%	0.02128	0.01875
Off-Peak	0.07214	0.06154	(0.01060)	-14.69%	0.02128	0.01875
Winter Season On-Peak	0.10527	0.08941	(0.01586)	-15.07%	0.02128	0.01875
Off-Peak	0.07388	0.06300	(0.01088)	-14.73%	0.02128	0.01875
Customer Charge - $/meter/month	89.65	89.65	0.00	0.00%	67.78	89.65
Facilities Related						
Demand Charge - $/kW	6.12	4.42	(1.70)	-27.78%	5.00	3.03
Time Related						
Demand Charge - $/kW	18.61	14.26	(4.35)	-23.37%	14.18	8.77
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00069)	(0.00069)			0.00000
Above 50 kV		(0.00148)	(0.00148)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.08)	(0.08)			(0.06)
Above 50 kV		(2.07)	(2.07)			(2.02)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.15)	(0.15)			(0.10)
Above 50 kV		(3.38)	(3.38)			(3.26)
TOU-8 (Below 2kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.12089	0.10483	(0.01606)	-13.29%	0.01659	0.01603
Mid-peak	0.07634	0.07103	(0.00531)	-6.95%	0.01659	0.01603
Off-Peak	0.06574	0.04996	(0.01578)	-24.01%	0.01659	0.01603
Winter Season						
Mid-peak	0.08288	0.08405	0.00117	1.41%	0.01659	0.01603
Off-Peak	0.06630	0.05108	(0.01522)	-22.96%	0.01659	0.01603
Customer Charge - $/month	334.55	334.55	0.00	0.00%	246.33	334.55
Facilities Related						
Demand Charge - $/kW	7.32	8.65	1.33	18.17%	6.35	7.33
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	17.63	22.33	4.70	26.66%	8.84	10.40
Mid-Peak	2.58	3.36	0.78	30.23%	0.76	0.89
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8 (From 2 kV to 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.11854	0.10775	(0.01079)	-9.10%	0.01567	0.01498
Mid-peak	0.07580	0.07226	(0.00354)	-4.67%	0.01567	0.01498
Off-Peak	0.06549	0.05152	(0.01397)	-21.33%	0.01567	0.01498
Winter Season						
Mid-peak	0.08186	0.08441	0.00255	3.12%	0.01567	0.01498
Off-Peak	0.06605	0.05267	(0.01338)	-20.26%	0.01567	0.01498
Customer Charge - $/month	334.95	334.95	0.00	0.00%	246.64	334.95
Facilities Related						
Demand Charge - $/kW	7.56	8.28	0.72	9.52%	6.58	6.88
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	18.11	22.43	4.32	23.85%	9.24	9.74
Mid-Peak	2.50	3.28	0.78	31.20%	0.78	0.82
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-8 (Above 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.10470	0.09026	(0.01444)	-13.79%	0.01182	0.01132
Mid-peak	0.06587	0.06492	(0.00095)	-1.44%	0.01182	0.01132
Off-Peak	0.05982	0.05089	(0.00893)	-14.93%	0.01182	0.01132
Winter Season						
Mid-peak	0.07072	0.07616	0.00544	7.70%	0.01182	0.01132
Off-Peak	0.06036	0.05216	(0.00820)	-13.59%	0.01182	0.01132
Customer Charge - $/month	391.46	391.46	0.00	0.00%	288.25	391.46
Facilities Related						
Demand Charge - $/kW	1.58	1.58	0.00	0.00%	1.58	1.58
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	13.49	18.00	4.51	33.43%	6.81	6.82
Mid-Peak	1.88	2.75	0.87	46.28%	0.59	0.59
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8 (Cont'd)						
Other Charges						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount, 220 kV and Above						
Energy - $/kWh		(0.00031)	(0.00031)			0.00000
Peak Demand - $/kW		(0.33)	(0.33)			(0.33)
Time-Related Demand - $/kW						
Summer		(3.55)	(3.55)			(3.51)
I-6 (below 2 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.10324	0.09385	(0.00939)	-9.10%	(0.00106)	0.00505
Mid-peak	0.06851	0.06226	(0.00625)	-9.12%	0.00876	0.00726
Off-Peak	0.06114	0.04485	(0.01629)	-26.65%	0.01199	0.01092
Winter Season						
Mid-peak	0.07341	0.07502	0.00161	2.19%	0.00712	0.00700
Off-Peak	0.06135	0.04627	(0.01508)	-24.58%	0.01164	0.01122
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	8.11	16.34	8.23	101.48%	(1.37)	4.41
Mid-Peak	1.25	2.58	1.33	106.40%	(0.37)	0.11
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
I-6 (from 2 kV to 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.10196	0.09818	(0.00378)	-3.70%	(0.00091)	0.00541
Mid-peak	0.06845	0.06421	(0.00424)	-6.20%	0.00832	0.00693
Off-Peak	0.06125	0.04626	(0.01499)	-24.47%	0.01143	0.00972
Winter Season						
Mid-peak	0.07301	0.07637	0.00336	4.61%	0.00682	0.00694
Off-Peak	0.06148	0.04770	(0.01378)	-22.41%	0.01110	0.01001
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	8.29	16.24	7.95	95.90%	(1.44)	3.55
Mid-Peak	1.31	2.49	1.18	90.08%	(0.06)	0.03
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
I-6 (above 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.09305	0.08250	(0.01055)	-11.34%	0.00017	0.00356
Mid-peak	0.06024	0.05779	(0.00245)	-4.07%	0.00619	0.00419
Off-Peak	0.05518	0.04528	(0.00990)	-17.95%	0.00718	0.00571
Winter Season						
Mid-peak	0.06395	0.06873	0.00478	7.48%	0.00505	0.00389
Off-Peak	0.05540	0.04660	(0.00880)	-15.89%	0.00686	0.00576
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	6.44	12.37	5.93	92.08%	(0.24)	1.19
Mid-Peak	0.83	2.07	1.24	149.40%	(0.47)	(0.09)
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
I-6 (Cont'd)						
Other Charges						
Excess Energy Charge - $/kWh						
Below 2 kV	9.30000	10.64895	1.34895	14.50%	9.30000	10.64895
From 2 kV to 50 kV	9.01000	10.42129	1.41129	15.66%	9.01000	10.42129
Above 50 kV	7.20000	10.05518	2.85518	39.66%	7.20000	10.05518
TOU-8-Backup (Below 2kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.12089	0.10483	(0.01606)	-13.28%	0.01659	0.01603
Mid-peak	0.07634	0.07103	(0.00531)	-6.96%	0.01659	0.01603
Off-Peak	0.06575	0.04996	(0.01579)	-24.02%	0.01659	0.01603
Winter Season						
Mid-peak	0.08289	0.08405	0.00116	1.40%	0.01659	0.01603
Off-Peak	0.06630	0.05108	(0.01522)	-22.96%	0.01659	0.01603
Customer Charge - $/month	182.76	182.76	0.00	0.00%	182.76	182.76
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	17.63	22.33	4.70	26.66%	8.84	10.40
Mid-Peak	2.58	3.36	0.78	30.23%	0.76	0.89
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8-Backup (From 2 kV to 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.11854	0.10775	(0.01079)	-9.10%	0.01567	0.01498
Mid-peak	0.07581	0.07226	(0.00355)	-4.68%	0.01567	0.01498
Off-Peak	0.06549	0.05152	(0.01397)	-21.33%	0.01567	0.01498
Winter Season						
Mid-peak	0.08186	0.08441	0.00255	3.12%	0.01567	0.01498
Off-Peak	0.06605	0.05267	(0.01338)	-20.26%	0.01567	0.01498
Customer Charge - $/month	182.94	182.94	0.00	0.00%	182.94	182.94
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	18.11	22.43	4.32	23.85%	9.24	9.74
Mid-Peak	2.50	3.28	0.78	31.20%	0.78	0.82
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-8-Backup (Above 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.10471	0.09026	(0.01445)	-13.80%	0.01182	0.01132
Mid-peak	0.06587	0.06492	(0.00095)	-1.44%	0.01182	0.01132
Off-Peak	0.05983	0.05089	(0.00894)	-14.94%	0.01182	0.01132
Winter Season						
Mid-peak	0.07072	0.07616	0.00544	7.69%	0.01182	0.01132
Off-Peak	0.06037	0.05216	(0.00821)	-13.60%	0.01182	0.01132
Customer Charge - $/month	186.97	186.97	0.00	0.00%	186.97	186.97
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	13.49	18.00	4.51	33.43%	6.81	6.82
Mid-Peak	1.87	2.75	0.88	47.06%	0.58	0.59
Winter Season						
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8-Backup (Cont'd)						
Other Charges						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount, 220 kV and Above						
Energy - $/kWh		(0.00031)	(0.00031)			0.00000
Peak Demand - $/kW		(0.33)	(0.33)			(0.33)
Time-Related Demand - $/kW						
Summer		(3.55)	(3.55)			(3.51)
TOU-8-SOP (Below 2 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.12320	0.10861	(0.01459)	-11.84%	0.01684	0.01620
Mid-peak	0.07549	0.06716	(0.00833)	-11.03%	0.01684	0.01620
Super Off-Peak	0.06175	0.05522	(0.00653)	-10.57%	0.01684	0.01620
Winter Season						
Mid-peak	0.07820	0.06951	(0.00869)	-11.11%	0.01684	0.01620
Super Off-Peak	0.06175	0.05522	(0.00653)	-10.57%	0.01684	0.01620
Customer Charge - $/month	334.55	334.55	0.00	0.00%	246.33	334.55
Facilities Related						
Demand Charge - $/kW	7.34	8.65	1.31	17.85%	6.38	7.33
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	36.72	34.83	(1.89)	-5.15%	11.72	13.11
Mid-Peak	0.96	0.90	(0.06)	-6.25%	0.27	0.30
Winter Season						
Mid-Peak	0.48	0.50	0.02	4.17%	0.32	0.36
Super Off-Peak	0.00	0.00	0.00		0.00	0.00

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	Total Bundled Rate Current	Total Bundled Rate Proposed	Total Bundled Rate Difference	Total Bundled Rate % Diff	Total Delivery Rate Current	Total Delivery Rate Proposed
TOU-8-SOP (From 2 kV to 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.11615	0.10441	(0.01174)	-10.11%	0.01605	0.01527
Mid-peak	0.07295	0.06594	(0.00701)	-9.61%	0.01605	0.01527
Super Off-Peak	0.06015	0.05454	(0.00561)	-9.33%	0.01605	0.01527
Winter Season						
Mid-peak	0.07549	0.06820	(0.00729)	-9.66%	0.01605	0.01527
Super Off-Peak	0.06015	0.05454	(0.00561)	-9.33%	0.01605	0.01527
Customer Charge - $/month	334.95	334.95	0.00	0.00%	246.64	334.95
Facilities Related						
Demand Charge - $/kW	7.56	8.28	0.72	9.52%	6.59	6.88
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	38.71	35.90	(2.81)	-7.26%	13.13	13.12
Mid-Peak	1.00	0.93	(0.07)	-7.00%	0.37	0.37
Winter Season						
Mid-Peak	0.63	0.61	(0.02)	-3.17%	0.49	0.49
Super Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8-SOP (Above 50 kV)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.09158	0.08285	(0.00873)	-9.53%	0.01212	0.01140
Mid-peak	0.05616	0.05100	(0.00516)	-9.19%	0.01212	0.01140
Super Off-Peak	0.05046	0.04587	(0.00459)	-9.10%	0.01212	0.01140
Winter Season						
Mid-peak	0.05776	0.05244	(0.00532)	-9.21%	0.01212	0.01140
Super Off-Peak	0.05046	0.04587	(0.00459)	-9.10%	0.01212	0.01140
Customer Charge - $/month	391.46	391.46	0.00	0.00%	288.25	391.46
Facilities Related						
Demand Charge - $/kW	1.64	1.58	(0.06)	-3.66%	1.64	1.58
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	31.45	29.07	(2.38)	-7.57%	9.35	9.20
Mid-Peak	0.90	0.84	(0.06)	-6.67%	0.41	0.40
Winter Season						
Mid-Peak	0.36	0.35	(0.01)	-2.78%	0.36	0.35
Super Off-Peak	0.00	0.00	0.00		0.00	0.00
TOU-8-SOP (Cont'd)						
Other Charges						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount, 220 kV and Above						
Energy - $/kWh		(0.00031)	(0.00031)			0.00000
Peak Demand - $/kW		(0.33)	(0.33)			(0.33)
Time-Related Demand - $/kW						
Summer		(3.55)	(3.55)			(3.51)
GS-APS (Schedules: GS-2, TOU-GS-2, or TOU-8)						
Air Conditioning Cycling Credit - $/ton/summer season month						
30% Cycling	(0.42)	(0.42)	0.00	0.00%	(0.42)	(0.42)
40% Cycling	(1.25)	(1.25)	0.00	0.00%	(1.25)	(1.25)
50% Cycling	(2.10)	(2.10)	0.00	0.00%	(2.10)	(2.10)
100% Cycling	(6.00)	(6.00)	0.00	0.00%	(6.00)	(6.00)
GS-APS-E (Schedules: GS-2, TOU-GS-2, or TOU-8)						
Air Conditioning Cycling Credit - $/ton/summer season month						
30% Cycling	(0.84)	(0.84)	0.00	0.00%	(0.84)	(0.84)
40% Cycling	(2.50)	(2.50)	0.00	0.00%	(2.50)	(2.50)
50% Cycling	(4.20)	(4.20)	0.00	0.00%	(4.20)	(4.20)
100% Cycling	(12.00)	(12.00)	0.00	0.00%	(12.00)	(12.00)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-BIP Option - $/kW (Applicable: Average kW demand)						
BIP Option Credit ($/KW)						
Below 2 kV		(7.10)	(7.10)			(7.10)
From 2 kV to 50 kV		(6.95)	(6.95)			(6.95)
Above 50 kV		(6.70)	(6.70)			(6.70)
Other Charges						
Excess Energy Charge - $/kWh						
Below 2 kV	9.30000	10.64895	1.34895	14.50%	9.30000	10.64895
From 2 kV to 50 kV	9.01000	10.42129	1.41129	15.66%	9.01000	10.42129
Above 50 kV	7.20000	10.05518	2.85518	39.66%	7.20000	10.05518
PA-1						
Energy Charge - $/kWh	0.10012	0.10736	0.00724	7.23%	0.03102	0.02979
Customer Charge - $/month	22.69	22.69	0.00	0.00%	22.69	22.69
Single Phase Discount - $/month		0.00	0.00			0.00
Service Charge - $/hp	2.57	1.82	(0.75)	-29.18%	2.56	1.82
Off Peak Credit - $/hp	(1.05)	(1.59)	(0.54)	51.43%	0.00	(1.59)
TOU Option Meter Charge - $/month		7.90	7.90			7.90
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00116)	(0.00116)			0.00000
Above 50 kV		(0.00251)	(0.00251)			0.00000
Voltage Discount, Service Charge - $/Hp						
From 2 kV to 50 kV		(0.04)	(0.04)			(0.04)
Above 50 kV		(1.20)	(1.20)			(1.20)
PA-2						
Energy Charge - $/kWh						
Summer	0.07763	0.08320	0.00557	7.17%	0.02084	0.01941
Winter	0.08323	0.08058	(0.00265)	-3.18%	0.02084	0.01941
Customer Charge - $/month	39.02	39.02	0.00	0.00%	39.02	39.02
Facilities Related						
Demand Charge - $/kW	3.66	2.96	(0.70)	-19.13%	3.66	2.96
Time Related Demand Charge - $/kW						
Summer Season	6.95	5.69	(1.26)	-18.13%	6.95	5.69
Winter Season	0.00	0.00	0.00		0.00	0.00
TOU Option Meter Charge - $/month						
Standard		16.06	16.06			16.06
TOU-RTEM		41.66	41.66			41.66
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00086)	(0.00086)			0.00000
Above 50 kV		(0.00186)	(0.00186)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.05)	(0.05)			(0.05)
Above 50 kV		(1.73)	(1.73)			(1.73)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.13)	(0.13)			(0.13)
Above 50 kV		(4.30)	(4.30)			(4.30)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-PA (Rate A)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.14017	0.13456	(0.00561)	-4.00%	0.02569	0.02613
Mid-peak	0.09312	0.09338	0.00026	0.28%	0.02569	0.02613
Off-Peak	0.06263	0.05194	(0.01069)	-17.07%	0.02569	0.02613
Winter Season						
Mid-peak	0.10166	0.10631	0.00465	4.57%	0.02569	0.02613
Off-Peak	0.06243	0.05194	(0.01049)	-16.80%	0.02569	0.02613
Customer Charge - $/month	50.51	50.51	0.00	0.00%	42.44	50.51
Service Charge - $/hp	3.55	3.67	0.12	3.38%	3.55	3.67
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00051)	(0.00051)			0.00000
Above 50 kV		(0.00111)	(0.00111)			0.00000
Voltage Discount, Service Charge - $/Hp						
From 2 kV to 50 kV		(0.07)	(0.07)			(0.07)
Above 50 kV		(2.19)	(2.19)			(2.19)
TOU-PA (Rate B)						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.10998	0.10957	(0.00041)	-0.37%	0.01627	0.02030
Mid-peak	0.07113	0.07712	0.00599	8.42%	0.01627	0.02030
Off-Peak	0.05436	0.05013	(0.00423)	-7.78%	0.01627	0.02030
Winter Season						
Mid-peak	0.07746	0.08730	0.00984	12.71%	0.01627	0.02030
Off-Peak	0.05436	0.05013	(0.00423)	-7.78%	0.01627	0.02030
Customer Charge - $/month	50.51	50.51	0.00	0.00%	42.44	50.51
Facilities Related						
Demand Charge - $/kW	4.18	4.18	0.00	0.00%	4.18	4.18
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	8.25	10.97	2.72	32.97%	6.38	8.08
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00049)	(0.00049)			0.00000
Above 50 kV		(0.00105)	(0.00105)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.10)	(0.10)			(0.10)
Above 50 kV		(3.46)	(3.46)			(3.46)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.21)	(0.21)			(0.18)
Above 50 kV		(6.19)	(6.19)			(6.11)
TOU-PA (Both Options)						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
TOU-PA-SOP						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.09245	0.08762	(0.00483)	-5.22%	0.01563	0.01622
Off-peak	0.05737	0.05501	(0.00236)	-4.11%	0.01563	0.01622
Super Off-Peak	0.04601	0.04446	(0.00155)	-3.37%	0.01563	0.01622
Winter Season						
Off-peak	0.05961	0.05710	(0.00251)	-4.21%	0.01563	0.01622
Super Off-Peak	0.04601	0.04446	(0.00155)	-3.37%	0.01563	0.01622
Customer Charge - $/month	50.51	50.51	0.00	0.00%	42.44	50.51
Facilities Related						
Demand Charge - $/kW	4.17	4.18	0.01	0.24%	4.17	4.18
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	35.12	32.64	(2.48)	-7.06%	0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
Winter Season						
Off-Peak	0.00	0.00	0.00		0.00	0.00
Super Off-Peak	0.00	0.00	0.00		0.00	0.00
Other Charges						
Power Factor Adjustment - $/kVA						
Greater than 50 kV	0.18	0.17	(0.01)	-5.56%	0.18	0.17
50 kV or less	0.23	0.19	(0.04)	-17.39%	0.23	0.19
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00049)	(0.00049)			0.00000
Above 50 kV		(0.00105)	(0.00105)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.10)	(0.10)			(0.10)
Above 50 kV		(3.46)	(3.46)			(3.46)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.03)	(0.03)			0.00
Above 50 kV		(0.08)	(0.08)			0.00
TOU-PA-5						
Energy Charge - $/kWh						
Summer Season						
On-Peak	0.09290	0.08086	(0.01204)	-12.96%	0.01461	0.01675
Mid-peak	0.06069	0.05757	(0.00312)	-5.14%	0.01461	0.01675
Off-Peak	0.05608	0.05044	(0.00564)	-10.05%	0.01461	0.01675
Winter Season						
Mid-peak	0.06541	0.06488	(0.00053)	-0.81%	0.01461	0.01675
Off-Peak	0.05950	0.05572	(0.00378)	-6.35%	0.01461	0.01675
Customer Charge - $/month	48.78	48.78	0.00	0.00%	42.44	48.78
Minimum Charge - $/kW						
Summer Season	25.55	37.51	11.96	46.79%	4.74	6.70
Winter Season	11.05	16.04	4.99	45.20%	4.04	5.67
Facilities Related						
Demand Charge - $/kW	4.16	6.43	2.27	54.57%	4.16	6.43
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak	6.21	7.06	0.85	13.69%	1.00	1.59
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Mid-Peak	0.00	0.00	0.00		0.00	0.00
Off-Peak	0.00	0.00	0.00		0.00	0.00
Voltage Discount or Surcharge, Energy - $/kWh						
From 2 kV to 50 kV		(0.00045)	(0.00045)			0.00000
Above 50 kV		(0.00096)	(0.00096)			0.00000
Voltage Discount, Peak Demand - $/kW						
From 2 kV to 50 kV		(0.13)	(0.13)			(0.13)
Above 50 kV		(4.27)	(4.27)			(4.27)
Voltage Discount, Time-Related Demand - $/kW						
From 2 kV to 50 kV		(0.10)	(0.10)			(0.04)
Above 50 kV		(1.35)	(1.35)			(1.20)

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
AP-I						
Interruptible Credit						
$/kWh	(0.00827)	(0.00973)	(0.00146)	17.65%	(0.00827)	(0.00973)
Excess Energy Charge - $/kWh						
Below 2 kV	6.04000	10.64895	4.60895	76.31%	6.04000	10.64895
From 2 kV to 50 kV	5.91000	10.42129	4.51129	76.33%	5.91000	10.42129
Above 50 kV	5.70000	10.05518	4.35518	76.41%	5.70000	10.05518
AL-2						
Energy Charge - $/kWh	0.07202	0.05204	(0.01998)	-27.75%	0.03172	0.00627
Customer Charge - $/month	18.56	18.56	0.00	0.00%	13.77	18.56
DWL						
Energy Charge - $/kWh	0.07202	0.06432	(0.00770)	-10.70%	0.03172	0.01855
Rate A - Other Charges						
High Pressure Sodium Vapor Lamp - $/lamp/month						
50 Watt	5.42	5.42	0.00	0.00%	5.16	5.42
70 Watt	5.48	5.48	0.00	0.00%	5.22	5.48
100 Watt	5.77	5.77	0.00	0.00%	5.51	5.77
150 Watt	5.77	5.77	0.00	0.00%	5.51	5.77
Metal Halide Lamp - $/lamp/month						
100 Watt	10.12	10.12	0.00	0.00%	9.86	10.12
175 Watt	9.30	9.30	0.00	0.00%	9.04	9.30
Mercury Vapor Lamp - $/lamp/month						
75 Watt	5.52	5.52	0.00	0.00%	5.26	5.52
Rate B - Other Charges						
High Pressure Sodium Vapor Lamp - $/lamp/month						
50 Watt	5.42	5.42	0.00	0.00%	5.16	5.42
70 Watt	5.48	5.48	0.00	0.00%	5.22	5.48
100 Watt	5.77	5.77	0.00	0.00%	5.51	5.77
150 Watt	5.77	5.77	0.00	0.00%	5.51	5.77
Metal Halide Lamp - $/lamp/month						
100 Watt	10.12	10.12	0.00	0.00%	9.86	10.12
175 Watt	9.30	9.30	0.00	0.00%	9.04	9.30
Mercury Vapor Lamp - $/lamp/month						
75 Watt	2.48	2.48	0.00	0.00%	2.22	2.48
DWL (Continued)						
Rate C - Other Charges						
High Pressure Sodium Vapor Lamp - $/lamp/month						
50 Watt	0.37	0.37	0.00	0.00%	0.37	0.37
70 Watt	0.37	0.37	0.00	0.00%	0.37	0.37
100 Watt	0.37	0.37	0.00	0.00%	0.37	0.37
150 Watt	0.37	0.37	0.00	0.00%	0.37	0.37
Metal Halide Lamp - $/lamp/month						
100 Watt	3.69	3.69	0.00	0.00%	3.69	3.69
175 Watt	3.45	3.45	0.00	0.00%	3.45	3.45
Mercury Vapor Lamp - $/lamp/month						
75 Watt	0.39	0.39	0.00	0.00%	0.39	0.39
Minimum Charge - $/month						
Rate A	100.00	100.00	0.00	0.00%	100.00	100.00
Rate B	50.00	50.00	0.00	0.00%	50.00	50.00

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
LS-1						
Energy Charge - $/kWh						
All Night Service	0.07202	0.06432	(0.00770)	-10.70%	0.03172	0.01855
Midnight Service	0.07401	0.06432	(0.00969)	-13.09%	0.03254	0.01855
Other Charges - All Night/Midnight Service						
Incandescent Lamps - $/lamp/month						
103 Watt	6.16	6.16	0.00	0.00%	5.90	6.16
202 Watt	6.18	6.18	0.00	0.00%	5.92	6.18
327 Watt	6.27	6.27	0.00	0.00%	6.01	6.27
448 Watt	6.61	6.61	0.00	0.00%	6.35	6.61
Mercury Vapor Lamps - $/lamp/month						
100 Watt	5.60	5.60	0.00	0.00%	5.34	5.60
175 Watt	5.63	5.63	0.00	0.00%	5.37	5.63
250 Watt	6.02	6.02	0.00	0.00%	5.76	6.02
400 Watt	6.34	6.34	0.00	0.00%	6.08	6.34
700 Watt	7.14	7.14	0.00	0.00%	6.88	7.14
1,000 Watt	6.89	6.89	0.00	0.00%	6.63	6.89
High Pressure Sodium Vapor Lamps - $/lamp/month						
50 Watt	5.59	5.59	0.00	0.00%	5.33	5.59
70 Watt	5.64	5.64	0.00	0.00%	5.38	5.64
100 Watt	5.94	5.94	0.00	0.00%	5.68	5.94
150 Watt	5.94	5.94	0.00	0.00%	5.68	5.94
200 Watt	6.34	6.34	0.00	0.00%	6.08	6.34
250 Watt	6.40	6.40	0.00	0.00%	6.14	6.40
400 Watt	6.67	6.67	0.00	0.00%	6.41	6.67
Low Pressure Sodium Vapor Lamps - $/lamp/month						
35 Watt	7.31	7.31	0.00	0.00%	7.05	7.31
55 Watt	7.10	7.10	0.00	0.00%	6.84	7.10
90 Watt	8.87	8.87	0.00	0.00%	8.61	8.87
135 Watt	9.11	9.11	0.00	0.00%	8.85	9.11
180 Watt	9.13	9.13	0.00	0.00%	8.87	9.13
LS-1 (Continued)						
Other Charges - All Night/Midnight Service						
Metal Halide Lamps - $/lamp/month						
75 Watt	11.35	11.35	0.00	0.00%	11.09	11.35
100 Watt	9.99	9.99	0.00	0.00%	9.73	9.99
175 Watt	9.16	9.16	0.00	0.00%	8.90	9.16
250 Watt	7.41	7.41	0.00	0.00%	7.15	7.41
400 Watt	7.07	7.07	0.00	0.00%	6.81	7.07
1,000 Watt	9.57	9.57	0.00	0.00%	9.31	9.57
1,500 Watt	21.75	21.75	0.00	0.00%	21.49	21.75
Tap Device Annual Charge						
$/device	21.09	21.09	0.00	0.00%	21.09	21.09

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
LS-2						
Energy Charge - $/kWh						
All Night Service	0.07202	0.06432	(0.00770)	-10.70%	0.03172	0.01855
Midnight Service	0.07401	0.06432	(0.00969)	-13.09%	0.03254	0.01855
Multiple Service (Other Charges)						
All Night/Midnight Service						
Incandescent Extended Service Lamps						
- $/lamp/month	1.27	1.27	0.00	0.00%	1.19	1.27
Mercury Vapor Lamps						
- $/lamp/month	1.27	1.27	0.00	0.00%	1.19	1.27
High Pressure Sodium Vapor Lamps - $/lamp/month						
50 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
70 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
100 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
150 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
200 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
250 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
310 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
400 Watt	1.27	1.27	0.00	0.00%	1.19	1.27
Low Pressure Sodium Vapor Lamps						
-$/lamp/month	1.27	1.27	0.00	0.00%	1.19	1.27
Metal Halide Lamps						
-$/lamp/month	1.27	1.27	0.00	0.00%	1.19	1.27
All Other Lamps						
-$/lamp/month	1.27	1.27	0.00	0.00%	1.19	1.27
LS-2 (Continued)						
Series Service						
Series Service Power Factor - $/kVar	0.23	0.19	(0.04)	-17.39%	0.23	0.19
All Night/Midnight Service						
Incandescent Extended Service Lamps						
-$/lamp/month	5.82	5.82	0.00	0.00%	5.79	5.82
Mercury Vapor Lamps						
-$/lamp/month	5.82	5.82	0.00	0.00%	5.79	5.82
High Pressure Sodium Vapor Lamps - $/lamp/month						
50 Watt	5.82	5.82	0.00	0.00%	5.79	5.82
70 Watt	5.82	5.82	0.00	0.00%	5.79	5.82
100 Watt	5.82	5.82	0.00	0.00%	5.79	5.82
150 Watt	5.82	5.82	0.00	0.00%	5.79	5.82
200 Watt	5.82	5.82	0.00	0.00%	5.79	5.82
250 Watt	0.00	N/A			N/A	N/A
310 Watt	0.00	N/A			N/A	N/A
400 Watt	0.00	N/A			N/A	N/A
Low Pressure Sodium Vapor Lamps						
-$/lamp/month	5.82	5.82	0.00	0.00%	5.79	5.82
Metal Halide Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
All Other Lamps						
-$/lamp/month	5.82	5.82	0.00	0.00%	5.79	5.82
Series Service Voltage Discount, Energy - $/kWh		(0.00108)	(0.00108)			0.00000

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	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
LS-2 Continued - (Optional Service - Relamp)						
Incandescent Extended Service Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
Mercury Vapor Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
High Pressure Sodium Vapor Lamps - $/lamp/month						
50 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
70 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
100 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
150 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
200 Watt	0.34	0.34	0.00	0.00%	0.34	0.34
250 Watt	0.34	0.34	0.00	0.00%	0.34	0.34
310 Watt	0.00	N/A			N/A	N/A
400 Watt	0.35	0.35	0.00	0.00%	0.35	0.35
Low Pressure Sodium Vapor Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
Metal Halide Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
All Other Lamps						
-$/lamp/month	0.00	N/A			N/A	N/A
LS-3						
Energy Charge - $/kWh	0.07202	0.05204	(0.01998)	-27.75%	0.03172	0.00627
Customer Charge - $/month						
Multiple Service	18.56	18.56	0.00	0.00%	13.77	18.56
Series Service	279.39	279.39	0.00	0.00%	274.74	279.39
Optional Relamp Service Charge ($/lamp/month)						
High Pressure Sodium Vapor Lamps						
50 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
70 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
100 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
150 Watt	0.33	0.33	0.00	0.00%	0.33	0.33
200 Watt	0.34	0.34	0.00	0.00%	0.34	0.34
250 Watt	0.34	0.34	0.00	0.00%	0.34	0.34
400 Watt	0.35	0.35	0.00	0.00%	0.35	0.35
Series Service						
Voltage Discount, Energy - $/kWh		(0.00108)	(0.00108)			0.00000

Appendix C

Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

		Total Bundled Rate				Total Delivery Rate	
		Current	Proposed	Difference	% Diff	Current	Proposed
OL-1							
Energy Charge - $/kWh							
	All Night Service	0.07202	0.06432	(0.00770)	-10.70%	0.03172	0.01855
	Midnight Service	0.07401	0.06432	(0.00969)	-13.09%	0.03254	0.01855
Pole Charge - $/pole/month		3.40	3.40	0.00	0.00%	3.40	3.40
Other Charges - All Night/Midnight Service							
Mercury Vapor Lamps - $/lamp/month							
	175 Watt	4.42	4.42	0.00	0.00%	4.16	4.42
	400 Watt	4.86	4.86	0.00	0.00%	4.60	4.86
High Pressure Sodium Vapor Lamps - $/lamp/month							
	50 Watt	4.36	4.36	0.00	0.00%	4.10	4.36
	70 Watt	4.42	4.42	0.00	0.00%	4.16	4.42
	100 Watt	4.42	4.42	0.00	0.00%	4.16	4.42
	150 Watt	4.42	4.42	0.00	0.00%	4.16	4.42
	200 Watt	4.86	4.86	0.00	0.00%	4.60	4.86
	250 Watt	4.94	4.94	0.00	0.00%	4.68	4.94
	400 Watt	5.24	5.24	0.00	0.00%	4.98	5.24
Low Pressure Sodium Vapor Lamps - $/lamp/month							
	35 Watt	5.72	5.72	0.00	0.00%	5.46	5.72
	55 Watt	5.72	5.72	0.00	0.00%	5.46	5.72
	90 Watt	6.82	6.82	0.00	0.00%	6.56	6.82
	135 Watt	6.62	6.62	0.00	0.00%	6.36	6.62
	180 Watt	6.71	6.71	0.00	0.00%	6.45	6.71
Metal Halide Lamps - $/lamp/month							
	75 Watt	4.78	4.78	0.00	0.00%	4.52	4.78
	100 Watt	5.25	5.25	0.00	0.00%	4.99	5.25
	175 Watt	4.58	4.58	0.00	0.00%	4.32	4.58
	250 Watt	4.70	4.70	0.00	0.00%	4.44	4.70
	400 Watt	4.95	4.95	0.00	0.00%	4.69	4.95
	1,000 Watt	6.08	6.08	0.00	0.00%	5.82	6.08
	1,500 Watt	6.97	6.97	0.00	0.00%	6.71	6.97
TC-1							
Energy Charge - $/kWh		0.09432	0.08480	(0.00952)	-10.09%	0.02730	0.02460
Customer Charge - $/day		0.40	0.40	0.00	0.00%	0.30	0.40
Three-Phase Service - $/day		0.079	0.090	0.011	13.92%	0.079	0.090
WTR							
Energy Charge - $/Device/Month							
50	0 - 50 kWh/month	18.42	14.02	(4.40)	-23.89%	11.13	11.01
100	51 - 100 kWh/month	27.03	18.22	(8.81)	-32.59%	12.46	12.20
150	101 - 150 kWh/month	35.70	22.49	(13.21)	-37.00%	13.85	13.46
200	151 - 200 kWh/month	44.33	26.69	(17.64)	-39.79%	15.20	14.65
250	201 - 250 kWh/month	53.01	30.95	(22.06)	-41.61%	16.59	15.90
300	251 - 300 kWh/month	61.65	35.20	(26.45)	-42.90%	17.95	17.14
350	301 - 350 kWh/month	70.30	39.43	(30.87)	-43.91%	19.31	18.36
400	351 - 400 kWh/month	78.94	43.68	(35.26)	-44.67%	20.68	19.60
450	401 - 450 kWh/month	87.58	47.90	(39.68)	-45.31%	22.03	20.81
500	451 - 500 kWh/month	96.23	52.17	(44.06)	-45.79%	23.40	22.07
Customer Charge - $/month		5.92	13.32	7.40	125.00%	4.44	13.32
Three-Phase Service - $/day		0.079	0.090	0.011	13.92%	0.079	0.090

Appendix C

Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

	Total Bundled Rate Current	Total Bundled Rate Proposed	Total Bundled Rate Difference	Total Bundled Rate % Diff	Total Delivery Rate Current	Total Delivery Rate Proposed
CPP-GCCD (Below 2kV)						
Energy Charge - $/kWh						
Summer Season						
Critical Peak		1.15203				0.01603
On-Peak		0.10483				0.01603
Mid-peak		0.07103				0.01603
Off-Peak		0.04996				0.01603
Winter Season						
Mid-peak		0.08405				0.01603
Off-Peak		0.05108				0.01603
Customer Charge - $/month		334.55				334.55
Facilities Related						
Demand Charge - $/kW		8.65				7.33
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak		10.40				10.40
Mid-Peak		0.89				0.89
Winter Season						
Mid-Peak		0.00				0.00
Off-Peak		0.00				0.00
CPP-GCCD (From 2 kV to 50 kV)						
Energy Charge - $/kWh						
Summer Season						
Critical Peak		1.13894				0.01498
On-Peak		0.10775				0.01498
Mid-peak		0.07226				0.01498
Off-Peak		0.05152				0.01498
Winter Season						
Mid-peak		0.08441				0.01498
Off-Peak		0.05267				0.01498
Customer Charge - $/month		334.95				334.95
Facilities Related						
Demand Charge - $/kW		8.28				6.88
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak		9.74				9.74
Mid-Peak		0.82				0.82
Winter Season						
Mid-Peak		0.00				0.00
Off-Peak		0.00				0.00

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Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

	Total Bundled Rate				Total Delivery Rate	
	Current	Proposed	Difference	% Diff	Current	Proposed
CPP-GCCD (Above 50 kV)						
Energy Charge - $/kWh						
Summer Season						
Critical Peak		1.02618				0.01132
On-Peak		0.09026				0.01132
Mid-peak		0.06492				0.01132
Off-Peak		0.05089				0.01132
Winter Season						
Mid-peak		0.07616				0.01132
Off-Peak		0.05216				0.01132
Customer Charge - $/month		391.46				391.46
Facilities Related						
Demand Charge - $/kW		1.58				1.58
Time Related Demand Charge - $/kW						
Summer Season						
On-Peak		6.82				6.82
Mid-Peak		0.59				0.59
Winter Season						
Mid-Peak		0.00				0.00
Off-Peak		0.00				0.00
Other Charges						
Power Factor Adjustment - $/kVA						
Greater than 50 kV		0.17				0.17
50 kV or less		0.19				0.19
Voltage Discount, 220 kV and Above						
Energy - $/kWh		(0.00031)				0.00000
Peak Demand - $/kW		(0.33)				(0.33)
Time-Related Demand - $/kW						
Summer		(3.55)				(3.51)

Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

SAPC Scaled	Trans	Dist	NDC	PPPC	TOTCA	PUCRF	DWR Bond	FTAC	Total Delivery	Generation URG	Generation DWR
STANDBY											
With Contract for Physical Assurance or for Maintenance Scheduled with SCE											
Customer Charge - $/month											
500 kW or less	0.00	74.03							74.03		
Below 2 kV	0.00	334.55							334.55		
From 2 kV to 50 kV	0.00	334.95							334.95		
Above 50, but < 220kV	0.00	391.46							391.46		
220 kV and above	0.00	391.46							391.46		
Maintenance Power Charge - $/kWh											
500 kW or less											
Summer Season											
On-Peak	0.00000	0.00980	0.00057	0.00398	0.00016	0.00012	0.00493		0.01956	0.10106	0.09056
Mid-peak	0.00000	0.00980	0.00057	0.00398	0.00016	0.00012	0.00493		0.01956	0.04514	0.09056
Off-Peak	0.00000	0.00980	0.00057	0.00398	0.00016	0.00012	0.00493		0.01956	0.01028	0.09056
Winter Season											
Mid-peak	0.00000	0.00980	0.00057	0.00398	0.00016	0.00012	0.00493		0.01956	0.06668	0.09056
Off-Peak	0.00000	0.00980	0.00057	0.00398	0.00016	0.00012	0.00493		0.01956	0.01212	0.09056
Summer Time Related Demand Charge - $/kW	0.00	0.00							0.00	5.94	
Peak Demand Charge - $/kW	0.00	0.00							0.00	2.44	
Below 2kV											
Summer Season											
On-Peak	0.00000	0.00939	0.00057	0.00342	0.00013	0.00012	0.00493		0.01856	0.10582	0.09056
Mid-peak	0.00000	0.00939	0.00057	0.00342	0.00013	0.00012	0.00493		0.01856	0.05490	0.09056
Off-Peak	0.00000	0.00939	0.00057	0.00342	0.00013	0.00012	0.00493		0.01856	0.02316	0.09056
Winter Season											
Mid-peak	0.00000	0.00939	0.00057	0.00342	0.00013	0.00012	0.00493		0.01856	0.07452	0.09056
Off-Peak	0.00000	0.00939	0.00057	0.00342	0.00013	0.00012	0.00493		0.01856	0.02485	0.09056
Summer Time Related Demand Charge - $/kW											
On-Peak	0.00	0.00							0.00	7.93	
Mid-Peak	0.00	0.00							0.00	1.47	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.32	
2kV - 50kV											
Summer Season											
On-Peak	0.00000	0.00843	0.00057	0.00322	0.00011	0.00012	0.00493		0.01738	0.11180	0.09056
Mid-peak	0.00000	0.00843	0.00057	0.00322	0.00011	0.00012	0.00493		0.01738	0.05834	0.09056
Off-Peak	0.00000	0.00843	0.00057	0.00322	0.00011	0.00012	0.00493		0.01738	0.02709	0.09056
Winter Season											
Mid-peak	0.00000	0.00843	0.00057	0.00322	0.00011	0.00012	0.00493		0.01738	0.07664	0.09056
Off-Peak	0.00000	0.00843	0.00057	0.00322	0.00011	0.00012	0.00493		0.01738	0.02883	0.09056
Summer Time Related Demand Charge - $/kW											
On-Peak	0.00	0.00							0.00	8.69	
Mid-Peak	0.00	0.00							0.00	1.46	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.40	
Above 50kV, but < 220kV											
Summer Season											
On-Peak	0.00000	0.00436	0.00057	0.00233	0.00008	0.00012	0.00493		0.01239	0.09097	0.09056
Mid-peak	0.00000	0.00436	0.00057	0.00233	0.00008	0.00012	0.00493		0.01239	0.05279	0.09056
Off-Peak	0.00000	0.00436	0.00057	0.00233	0.00008	0.00012	0.00493		0.01239	0.03166	0.09056
Winter Season											
Mid-peak	0.00000	0.00436	0.00057	0.00233	0.00008	0.00012	0.00493		0.01239	0.06973	0.09056
Off-Peak	0.00000	0.00436	0.00057	0.00233	0.00008	0.00012	0.00493		0.01239	0.03357	0.09056
Summer Time Related Demand Charge - $/kW											
On-Peak	0.00	0.00							0.00	7.18	
Mid-Peak	0.00	0.00							0.00	1.16	
Peak Demand Charge - $/kW	0.00	0.00							0.00	0.00	
220kV and above											
Summer Season											
On-Peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.09051	0.09056
Mid-peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.05233	0.09056
Off-Peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.03120	0.09056
Winter Season											
Mid-peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.06927	0.09056
Off-Peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.03311	0.09056
Summer Time Related Demand Charge - $/kW											
On-Peak	0.00	0.00							0.00	7.11	
Mid-Peak	0.00	0.00							0.00	1.15	
Peak Demand Charge - $/kW	0.00	0.00							0.00	0.00	

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Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

SAPC Scaled	Trans	Dist	NDC	PPPC	TOTCA	PUCRF	DWR Bond	FTAC	Total Delivery	Generation URG	Generation DWR
Without Contract for Physical Assurance											
Customer Charge - $/month											
500 kW or less											
	0.00	74.03							74.03	0.00	
Below 2 kV											
From 2 kV to 50 kV	0.00	334.55							334.55	0.00	
Above 50, but < 220kV	0.00	334.95							334.95	0.00	
220kV and above	0.00	391.46							391.46	0.00	
	0.00	391.46							391.46	0.00	
Capacity Reservation Charge - $/kW											
500 kW or less											
	0.30	4.02							4.32	0.00	
Below 2 kV											
From 2 kV to 50 kV	0.30	4.02							4.32	0.00	
Above 50 kV, but < 220kV	0.23	3.93							4.16	0.00	
220kV and above	0.17	0.98							1.15	0.00	
	0.17	0.00							0.17	0.00	
Peak Demand Charge - $/kWh											
500 kW or less											
Summer Season											
On-Peak											
Mid-peak	0.00000	0.01560	0.00057	0.00398	0.00016	0.00012	0.00493		0.02536	0.10106	0.09056
Off-Peak	0.00000	0.01560	0.00057	0.00398	0.00016	0.00012	0.00493		0.02536	0.04514	0.09056
Winter Season	0.00000	0.01560	0.00057	0.00398	0.00016	0.00012	0.00493		0.02536	0.01028	0.09056
Mid-peak											
Off-Peak	0.00000	0.01560	0.00057	0.00398	0.00016	0.00012	0.00493		0.02536	0.06668	0.09056
Summer Time Related Demand Charge - $/kW	0.00000	0.01560	0.00057	0.00398	0.00016	0.00012	0.00493		0.02536	0.01212	0.09056
Peak Demand Charge - $/kW	0.00	0.00							0.00	5.94	
	0.00	0.00							0.00	2.44	
Below 2kV											
Summer Season											
On-Peak											
Mid-peak	0.00000	0.01519	0.00057	0.00342	0.00013	0.00012	0.00493		0.02436	0.10582	0.09056
Off-Peak	0.00000	0.01519	0.00057	0.00342	0.00013	0.00012	0.00493		0.02436	0.05490	0.09056
Winter Season	0.00000	0.01519	0.00057	0.00342	0.00013	0.00012	0.00493		0.02436	0.02316	0.09056
Mid-peak											
Off-Peak	0.00000	0.01519	0.00057	0.00342	0.00013	0.00012	0.00493		0.02436	0.07452	0.09056
Summer Time Related Demand Charge - $/kW	0.00000	0.01519	0.00057	0.00342	0.00013	0.00012	0.00493		0.02436	0.02485	0.09056
On-Peak											
Mid-Peak	0.00	0.00							0.00	7.93	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.47	
	0.00	0.00							0.00	1.32	
2kV - 50kV											
Summer Season											
On-Peak											
Mid-peak	0.00000	0.02007	0.00057	0.00322	0.00011	0.00012	0.00493		0.02902	0.11180	0.09056
Off-Peak	0.00000	0.02007	0.00057	0.00322	0.00011	0.00012	0.00493		0.02902	0.05834	0.09056
Winter Season	0.00000	0.02007	0.00057	0.00322	0.00011	0.00012	0.00493		0.02902	0.02709	0.09056
Mid-peak											
Off-Peak	0.00000	0.02007	0.00057	0.00322	0.00011	0.00012	0.00493		0.02902	0.07664	0.09056
Summer Time Related Demand Charge - $/kW	0.00000	0.02007	0.00057	0.00322	0.00011	0.00012	0.00493		0.02902	0.02883	0.09056
On-Peak											
Mid-Peak	0.00	0.00							0.00	8.69	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.46	
	0.00	0.00							0.00	1.40	
Above 50kV, but < 220kV											
Summer Season											
On-Peak											
Mid-peak	0.00000	0.00813	0.00057	0.00233	0.00008	0.00012	0.00493		0.01616	0.09097	0.09056
Off-Peak	0.00000	0.00813	0.00057	0.00233	0.00008	0.00012	0.00493		0.01616	0.05279	0.09056
Winter Season	0.00000	0.00813	0.00057	0.00233	0.00008	0.00012	0.00493		0.01616	0.03166	0.09056
Mid-peak											
Off-Peak	0.00000	0.00813	0.00057	0.00233	0.00008	0.00012	0.00493		0.01616	0.06973	0.09056
Summer Time Related Demand Charge - $/kW	0.00000	0.00813	0.00057	0.00233	0.00008	0.00012	0.00493		0.01616	0.03357	0.09056
On-Peak											
Mid-Peak	0.00	0.00							0.00	7.18	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.16	
	0.00	0.00							0.00	0.00	

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Phase 2 Rate Design Agreement
2003 GRC Settlement Agreement

SAPC Scaled	Trans	Dist	NDC	PPPC	TOTCA	PUCRF	DWR Bond	FTAC	Total Delivery	Generation URG	Generation DWR
Without Contract for Physical Assurance - Continue											
220kV and above											
Summer Season											
On-Peak											
Mid-peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.09051	0.09056
Off-Peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.05233	0.09056
Winter Season	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.03120	0.09056
Mid-peak											
Off-Peak	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.06927	0.09056
Summer Time Related Demand Charge - $/kW	0.00000	0.00309	0.00057	0.00233	0.00008	0.00012	0.00493		0.01112	0.03311	0.09056
On-Peak											
Mid-Peak	0.00	0.00							0.00	7.11	
Peak Demand Charge - $/kW	0.00	0.00							0.00	1.15	
	0.00	0.00							0.00	0.00	
Standby Other Charges											
Power Factor Adjustment - $/kVA											
Greater than 50 kV											
50 kV or less		0.17							0.17		