SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. The details of this Settlement Agreement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- Agricultural Energy Consumers Association (AECA)
- Building Owners and Managers Associations of San Francisco, Greater Los Angeles, Orange County and California (BOMA)
- California City-County Street Light Association (CAL-SLA)
- California Farm Bureau Federation (CFBF)
- California Large Energy Consumers Association (CLECA)
- California League of Food Processors (CLFP)
- California Manufacturers & Technology Association (CMTA)
- California Retailers Association (CRA)
- California Rice Millers
- California Solar Energy Industries Association (CAL SEIA)
- Cogeneration Association of California (CAC)
- Direct Access Customer Coalition (DACC)
- Division of Ratepayer Advocates (DRA)

- Energy Producers and Users Coalition (EPUC)
- Energy Users Forum (EUF)
- Federal Executive Agencies (FEA)
- Indicated Commercial Parties (ICP)
- Pacific Gas and Electric Company (PG&E)
- PV Now (PV Now)
- The Utility Reform Network (TURN)
- Vote Solar
- The Western Manufactured Housing Communities Association (WMA)

III. SETTLEMENT CONDITIONS

This Settlement Agreement resolves the issues raised by the Settling Parties in A.06-03-005 on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This Settlement Agreement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Settlement Agreement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this Settlement Agreement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this Settlement Agreement shall be construed against any Settling Party because that Settling Party or its counsel or

advocate drafted the provision.

5. This Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this Settlement Agreement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement Agreement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of this Settlement Agreement. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding marginal cost and revenue allocation issues and requested a further extension of the procedural schedule to memorialize the settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007.

V. SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of determining marginal costs in this proceeding is to establish the cost of providing service by rate group for the generation and distribution functions. In addition, the Settling Parties agree that, since marginal costs were last adopted for revenue allocation and rate design purposes in 1993, this proceeding should result in updated marginal costs. While the Settling Parties disagree on the specific principles that should be employed to calculate marginal costs, the Settling Parties generally agree on the marginal cost values to be employed for the defined purposes described in this Settlement Agreement.

Considering the marginal costs agreed to, and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this Settlement Agreement. The revenue allocation percentages and procedures agreed to in this Settlement Agreement better align customer class average rates with the customer class costs of service that would be calculated based on the negotiated marginal cost values.

No later than February 9, 2007, PG&E and DRA will jointly serve a comparison exhibit showing the impact of the Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a).

The Settling Parties agree that all testimony served prior to the date of this Settlement Agreement that addresses the issues resolved by this Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree that this Settlement Agreement will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.06-03-005. To the extent all issues are not settled, the Settling Parties agree to pursue litigation in this proceeding on those issues only, provided those issues do not affect the outcome of issues agreed upon in this Settlement Agreement.

VI. MARGINAL COST SETTLEMENT

1. Marginal Cost Principles and Purposes

This Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VII below. The Settling Parties agree that it is reasonable for the Commission to approve the marginal costs in this Settlement Agreement for the purpose of establishing unit costs in the development of revenue allocation and rate design in this proceeding and for customer-specific contract rate floors for customer retention and attraction. In addition to the foregoing uses, nothing in this Settlement Agreement shall preclude any Settling Party from advocating the use of the marginal distribution capacity costs, marginal customer costs and marginal transmission capacity costs adopted in this Settlement Agreement, or any other values for these cost components, for the purpose of avoided cost modeling, as described below. The Settling Parties acknowledge that the marginal costs presented here were considered by the Settling Parties in the negotiation of the settled revenue allocation recommendation but were not the sole basis of that recommendation.

The generation capacity costs and marginal energy costs in this Settlement Agreement are adopted for the purposes of (i) settling revenue allocation and rate design in this proceeding, and (ii) developing customer-specific contract rate floors for customer retention and attraction. The Settling Parties agree that the use of these negotiated generation capacity costs and marginal energy costs in this Settlement Agreement may not be cited or used as a precedent in other Commission proceedings, including but not limited to, avoided cost modeling and/or capacity for any resource, including QFs. If the Commission adopts new marginal generation costs/methodologies, the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the Settlement Agreement revenue allocation and rate design. Nothing in this Settlement Agreement shall preclude any

Settling Party from advocating marginal cost values generated by the Settling Party's own methodology or any such new Commission methodologies for (i) customer-specific contract rate floors for customer retention and attraction, and/or (ii) avoided cost modeling in other Commission proceedings.

2. Generation Marginal Energy Costs

The Settling Parties agree to use the following marginal generation energy costs:

Table 1

Marginal Energy Costs ($/MWh) by TOU Period and Voltage Level For 2007[1]

		Voltage Level		
Line No.	TOU	Transmission	Primary distribution	Secondary distribution
1	Summer On Peak	95.23	98.37	103.09
2	Summer Partial-Peak	76.41	78.85	81.14
3	Summer Off Peak	65.17	66.74	68.07
4	Winter-Partial	69.59	71.47	74.97
5	Winter-Off	61.82	63.24	64.51
6	Average	68.78	70.57	72.54

3. Marginal Generation Capacity Costs

The Settling Parties do not agree on a marginal generation capacity cost but do agree to use the following generation capacity values:

[1] Source: PG&E 2007 General Rate Case Phase 2, Exhibit (PG&E-2), Chapter 2 Update, Marginal Generation Cost Update Testimony, Table 2-1, December 22, 2006. "TOU" means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary for cost and price differences.

Table 2
Generation Capacity Costs ($/kW-yr)[2]

VOLTAGE LEVEL	Generation capacity cost per kW of demand
TRANSMISSION	84.00
PRIMARY	86.77
SECONDARY	90.94

4. Marginal Distribution Capacity Cost

The Settling Parties agree to use the following marginal distribution capacity costs by Division[3] [4]:

[2] For purposes of this Settlement Agreement, the generation capacity values include all necessary adjustments to properly reflect the cost of demand, including adjustments for planning reserve benefit. The agreement to use the generation capacity values in this Settlement Agreement may not be cited or used as precedent in other Commission proceedings where generation capacity values, avoided cost methodology, and/or the value of any resource, including QFs, are at issue.

[3] "Division" means PG&E's 18 divisions for which distribution marginal costs are reported: Central Coast, De Anza, Diablo, East Bay, Fresno, Kern, Los Padres, Mission, North Bay, North Coast, North Valley, Peninsula, Sacramento, San Francisco, San Jose, Sierra, Stockton, Yosemite.

[4] Marginal distribution costs are calculated by taking PG&E's proposal in A.06-03-005 and changing the calculation to scale the Division-level discounted total investment method to system-wide regression values.

Table 3

Marginal Distribution Capacity Cost (MDCC)

	PRIMARY DISTRIBUTION $/PCAF-kW-YEAR	SECONDARY DISTRIBUTION $/FLT-kW-YEAR	NEW BUSINESS PRIMARY DISTRIBUTION $/FLT kW-YEAR
SYSTEM AVERAGE	31.31	0.70	1.90
CENTRAL COAST	46.37	0.90	1.45
DE ANZA	14.23	0.90	1.28
DIABLO	56.91	1.07	2.49
EAST BAY	16.06	0.58	1.67
FRESNO	26.65	0.36	1.43
KERN	10.93	0.36	2.08
LOS PADRES	72.08	1.76	3.18
MISSION	23.84	0.71	2.29
NORTH BAY	38.22	0.94	1.61
NORTH COAST	40.98	0.79	1.83
NORTH VALLEY	58.83	1.11	2.27
PENINSULA	33.11	0.99	1.70
SACRAMENTO	25.43	0.85	1.91
SAN FRANCISCO	39.56	0.65	0.75
SAN JOSE	23.18	0.82	1.73
SIERRA	28.91	0.52	2.11
STOCKTON	28.89	0.56	2.60
YOSEMITE	18.33	0.49	2.34

The Settlement Agreement marginal distribution capacity costs may be proposed for use in avoided cost modeling in other Commission proceedings, including Phase 3 of R.04-04-025, where applicable, in addition to the uses allowed above. However, Settling Parties are not bound to support the use of these costs in other proceedings.[5]

[5] For primary distribution only, the Division-level marginal costs are based on DPA-level investment and load forecasts. For purposes requiring DPA-level detail (e.g. to establish customer-specific contract rate floors as applicable, and for avoided cost modeling in other Commission proceedings, including Phase 3 of R.04-04-025), DPA marginal distribution costs under this Settlement Agreement would be calculated by applying the primary distribution scaling factor of 1.2689 to PG&E's proposed marginal distribution capacity costs for the DPAs shown in PG&E's June 26, 2006 workpapers. "DPAs" means "distribution planning areas", the specific geographic study areas that PG&E uses for distribution expansion planning. There are 242 DPAs in PG&E's Application 06-03-005.

5. Marginal Customer Costs

The Settling Parties do not agree on a marginal customer cost but agree to use the following customer costs for purposes of this proceeding:

Table 4

Marginal Customer Costs

RATE GROUP	$/CUSTOMER-YEAR
RESIDENTIAL TOTAL	103.13
AGRICULTURAL A	279.16
AGRICULTURAL B	444.69
A1 SMALL L & P	272.45
A10 MEDIUM L & P PRIMARY	622.07
A10 MEDIUM L & P SECONDARY	986.94
E19 PRIMARY	7,626.99
E19 SECONDARY	6,432.47
E19 TRANSMISSION	11,509.08
E20 PRIMARY	7,624.79
E20 SECONDARY	6,481.60
E20 TRANSMISSION	11,509.08
STREETLIGHTS	61.11

The Settlement Agreement marginal customer costs may be proposed for use in avoided cost modeling in other Commission proceedings, including Phase 3 of R.04-04-025, if applicable, in addition to the uses allowed above. However, Settling Parties are not bound to support the use of these costs in other proceedings.

6. Marginal Transmission Costs

The Settling Parties agree to use a marginal transmission cost of $6.39 per kW-year on a system average basis. The Settlement Agreement marginal transmission capacity cost may be proposed for use in avoided cost modeling in other Commission proceedings, including Phase 3 of R.04-04-025, if applicable, in addition to the uses allowed above. However, Settling Parties are not bound to support the use of these costs in other proceedings.

The Settlement Agreement marginal transmission capacity cost may not be used for transmission-related revenue allocation and rate design purposes, which shall instead be based upon Federal Energy Regulatory Commission (FERC) jurisdictional determinations.

VII. REVENUE ALLOCATION SETTLEMENT

1. Agreed-Upon Allocation Principles

The Settling Parties agree that electric revenue should be allocated as a result of A.06-03-005 on an overall revenue-neutral basis to preserve then-current total authorized revenue. The Settling Parties agree that the revenue allocation shall be computed using the marginal costs presented in Section VI above, along with the following adjustments:

(A) Generation and distribution revenue shall be adjusted 85 percent of the way from then-current distribution and generation revenue to revenue at equal percent of the marginal cost, defined based on the other portions of this Settlement Agreement.

(B) The allocation of distribution-level costs to distribution-voltage service level standby customers is further adjusted to reflect only 60 percent of their subscribed contract capacity.

(C) Current and proposed generation revenue developed to assess the movement to full cost will exclude non-allocated revenue (other standby generation revenue) as well as the adjustment to core and non-core bundled generation rates pursuant to D. 06-07-030 (i.e., the Cost Responsibility Surcharge decision).

(D) Current and proposed distribution revenue developed to assess the movement to full cost will exclude non-allocated revenue (i.e., other standby distribution revenue, nonfirm/E-BIP discounts, streetlight facility charges, meter charges, employee discounts, retention and attraction discounts, and the Schedule A-15 facilities charge), the estimated California Alternate Rates for Energy (CARE) program discount, the cost of the Self-Generation Incentive Program (SGIP), the cost of the California Solar Initiative (CSI), and the cost of PG&E's Climate Protection Tariff (CPT), and the cost of PG&E's nonfirm/E-BIP program. The estimated cost of CARE program discount includes discounts currently provided as distribution and generation discounts. The estimated CARE discount is then directly assigned to reduce distribution revenue to eligible CARE customers as required by D. 05-12-041.

(E) The Settling Parties agree that nothing in this Settlement Agreement shall be precedential regarding future allocation of the costs of the Annual Earnings Assessment Proceeding (AEAP) or any successor proceeding pertaining to the allocation of the costs of energy efficiency shareholder incentives.

(F) Rates for CARE customers shall not be increased under this Settlement Agreement. Nothing in this Settlement Agreement precludes any of the Settling Parties from raising as an issue in other Commission proceedings the level of the CARE discount or the overall cost of the program.

(G) All nonfirm customers will transfer to Schedule E-BIP on or before January 1, 2008. The Schedule E-BIP discounts will be equal to the 2007 Schedule E-BIP discounts for Option A adopted by D. 06-11-049, p. 27.

(H) Streetlight Facilities Charge revenue is set equal to $17,550,250.

(I) The costs of SGIP, CSI, CPT, and nonfirm/E-BIP discounts will be allocated based on equal percent of total revenue after generation revenue is imputed for direct access customers. After allocating these costs based on equal percent of total revenue, they will be added to other distribution costs to determine distribution rates.

(J) In order to reduce significant bill impacts on DA customers, increases to E-20 T DA and E-20 P DA have been adjusted. Distribution revenue for Schedule E-20 T is adjusted such that Schedule E-20 T direct access distribution revenue for firm service does not change compared to the level of present rate distribution revenues. Distribution revenue for Schedule E-20 P is adjusted such that Schedule E-20 P direct access distribution revenue for firm service is reduced by one million dollars relative to the then-current proposed distribution revenue determined immediately before application of the distribution caps described in this section. The shortfall resulting from this capping is shared by all other customers based on equal percent of allocated distribution revenue (i.e., distribution revenue excluding CARE discounts and non-allocated revenue).

(K) Public Purpose Program revenue will be allocated as follows: The estimated cost of CARE distribution discount (the new distribution discount includes the amount that was previously provided as a generation discount), any under or over collection of the CARE balancing account and the cost of administration of this program will be allocated among customer groups based on equal cents per kWh. The costs of the Low Income Energy Efficiency Program and the Procurement Energy Efficiency Program will be allocated on the basis of equal percent of total revenue after generation revenue is imputed for direct access customers. Allocation of the remaining PPP revenue will be unchanged.

(L) As a final step, annual average bundled rates will be limited by adjusting the generation allocation such that total bundled rates change as provided below. Any resulting shortfall is collected from all other customer groups except Standby based on an equal percent of generation revenue.

Residential Class: 2.8%

A-10 Class: -5.0%

E-19 Secondary (firm and nonfirm combined): -9.0%

Agricultural Class: 4.0%

Streetlighting Class: -9.0%

E-20 Transmission Firm: 0.0%

E-20 Primary Firm: -2.0%

E-20 Secondary Firm: -9.0%

Illustrative average electric rates that are expected to result from this Settlement Agreement are provided in Tables 6-A (bundled service) and 6-B (direct access service). For purposes of this Settlement Agreement, present average rates are based on an estimate of rates after inclusion of the proposed settlement in Phase 1 of the 2007 GRC, Transmission Owner 9, the 2007 change to the transmission access charge balancing account and the 2007 nuclear decommissioning rate change.   The Settling Parties agree that the average rates and percentage change set forth herein are estimates of the actual allocation results that will be calculated in accordance with this settlement and that actual results may be somewhat different. In addition, schedule level percentage changes not specifically shown below will be addressed in future rate design settlement agreements and may vary from the class average percentage changes shown.

Table 5-A
Revenue Allocation Settlement (Bundled)

	Projected March 2007 Rates	Illustrative Average Settlement Rates	Percent Change
Bundled			
Residential			
CARE	$0.08634	$0.08630	0.0%
Non-CARE	$0.16553	$0.17076	3.2%
Small L&P	$0.15854	$0.16740	5.6%

Medium L&P	$0.14498	$0.13771	-5.0%
E-19T	$0.11134	$0.10019	-10.0%
E-19P	$0.11404	$0.11156	-2.2%
E-19S	$0.13029	$0.11855	-9.0%
Streetlights	$0.16947	$0.15422	-9.0%
Standby	$0.11680	$0.12020	2.9%
Agriculture	$0.12328	$0.12820	4.0%
E-20T firm	$0.08408	$0.08407	0.0%
E-20T NF	$0.07211	$0.06854	-5.0%
E-20P firm	$0.10779	$0.10562	-2.0%
E-20P NF	$0.10284	$0.09654	-6.1%
E-20S firm	$0.12648	$0.11509	-9.0%
E-20S NF	$0.11703	$0.10043	-14.2%
Total	$0.13962	$0.13945	-0.1%

Table 5-B
Revenue Allocation Settlement (Direct Access)

	Projected March 2007 Rates	Illustrative Settlement Rates	Percent Change
Direct Access			
Residential			
CARE	$0.04991	$0.01385	-72.2%
Non-CARE	$0.08078	$0.08561	6.0%
Small L&P	$0.06934	$0.08017	15.6%
Medium L&P	$0.04637	$0.04964	7.0%
E-19P	$0.03333	$0.04079	22.4%
E-19S	$0.04588	$0.04382	-4.5%
Agriculture	$0.04287	$0.04047	-5.6%
E-20T firm	$0.01825	$0.02127	16.6%
E-20T NF	$0.00456	$0.00461	1.1%
E-20P firm	$0.03082	$0.03564	15.7%
E-20P NF	$0.01967	$0.02113	7.4%
E-20S firm	$0.04553	$0.04206	-7.6%
E-20S NF	$0.03901	$0.03029	-22.4%
Total	$0.03332	$0.03506	5.2%

2. Timing of Rate Change

Should the rate change pursuant to this Settlement Agreement occur in 2007, it shall be based on the sales forecast adopted in the 2007 Energy Resource Recovery Account (ERRA) proceeding (A.06-06-001) in D.06-12-018. If these rate changes are not implemented until January 1, 2008, the rate change on January 1, 2008 will be conducted in two steps: (1) allocation pursuant to this agreement based on the 2007 sales forecast; and then (2) allocation of revised revenue requirements pursuant to the

2008 Annual Electric True Up (AET), based on the 2008 sales forecast and the guidelines set forth in Section 3 below regarding Rate Changes Between General Rate Cases. Should the rate change implementing this Settlement Agreement not occur until after January 1, 2008, PG&E will incorporate the settlement into rates based on then-current rates and the 2008 sales forecast. PG&E will then consult with the Settling Parties prior to implementation to ensure parties agree that the benefits of the Settlement Agreement are preserved.

3. Rate Changes Between General Rate Cases (GRCs)

After rates are implemented pursuant to the decision in A.06-03-005, rates will be changed to reflect changes to the revenue requirement in the manner set forth below.

(A) Each customer group will be held responsible for approximately the same percentage contribution to each component of rates. Except as noted below, this will be accomplished by implementing changes to the revenue requirement for each component by applying to each rate schedule the same percentage change to rates by component required to collect the revenue requirement for that component.

(B) Generation revenue developed to determine the appropriate starting point to apply the percentages from (A) will exclude non-allocated revenue as well as the adjustment to core and non-core bundled generation rates pursuant to D. 06-07-030 (i.e., the Cost Responsibility Surcharge decision). In addition, for rate changes where there is a change to Competition Transition Charges (CTC), current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.

(C) The 100 peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual Energy Resource Recovery Account (ERRA) forecast application.

(D) Distribution revenue developed to determine the appropriate starting point to apply the percentages from (A) will exclude non-allocated revenue and the estimated California Alternate Rates for Energy (CARE) program discounts. The cost of the SGIP, the cost of the CSI, the cost of CPT, and the cost of nonfirm/E-BIP discounts will be included in current distribution revenue and the proposed distribution revenue requirement.

(E) Generally, the revenue to be collected from the CARE surcharge will only change between GRCs due to changes in the level of CARE program participation, changes in forecast sales, under- or over-collection of the CARE balancing account, and/or changes to the CARE administrative costs. Changes to the differential between CARE and non-CARE rates will neither increase nor decrease the revenue to be collected in the CARE surcharge.

Specifically, between GRCs, the CARE surcharge rate will be modified each year as part of the AET, using the following steps:

1. The differentials between CARE and non-CARE total bundled rates (less DWR Bond Charges and CARE Surcharges) that result from this Settlement Agreement will be known as the “CARE Shortfall rates.” The CARE Shortfall rates will be differentiated by schedule and tier, and will not change between GRCs unless otherwise ordered by the Commission.
2. The product of the CARE Shortfall rates and the forecast of CARE sales will be the CARE Shortfall RRQ.
3. The sum of the CARE Shortfall RRQ, the CARE administration costs and the CARE balancing account balances will be the CARE Surcharge RRQ.
4. The CARE Surcharge rate will be calculated by dividing the CARE Surcharge RRQ by the forecast of sales eligible to pay the CARE surcharge.
5. The CARE shortfall rates multiplied by the actual CARE sales will be entered as a CARE cost in the CARE balancing account along with the CARE administrative cost and any over- or undercollection. The CARE surcharge multiplied by the actual sales to customers eligible to pay the CARE surcharge will serve as the revenue entry to the CARE balancing account.

(F) This section describes how to allocate changes in Public Purpose Program (PPP) revenue between rate cases. First, total PPP revenue for each rate schedule will be set by increasing current PPP revenue by the sum of the following three pieces: (1) each rate schedule's share of any incremental CARE surcharge revenue, allocated on an equal percent of current PPP revenue basis, for customers subject to the CARE surcharge; (2) each rate schedule's share of any incremental Energy Efficiency (EE), Renewable and Research, Development and Demonstration (RD&D) revenue, allocated on an equal percent of current EE, Renewable and RD&D revenue basis, subject to the capping requirements of Public Utilities Code Section 399.8 (c) 2; and (3) each rate schedule's share of any incremental Procurement EE and Low Income EE revenue, allocated on an equal percent of current Procurement EE and Low Income EE revenue basis.

Second, actual revenue by component will be determined for each rate schedule as follows: (1) CARE surcharge revenue will be determined on an equal cents per kWh basis; (2) EE, Renewable and RD&D revenue will be equal to current EE, Renewable and RD&D revenue plus the schedule-level increments described in part (2) of the preceding paragraph; and (3) Procurement EE and Low Income EE revenue will be calculated residually as the difference between the total revised PPP revenue described in the preceding paragraph and the sum of (1) and (2) described in this paragraph.

(G) Non-residential rate changes will be implemented as equal percentage changes to demand and energy charges by component as necessary to collect the assigned revenue. Customer charges, streetlighting facilities charges, meter charges and minimum charges will be unchanged between general rate cases,[6] unless revised by separate Commission decision (for example, a Rate Design Window proceeding).

(H) Residential rate design between general rate cases will be addressed in the settlement on residential rate design.

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[6] In rare instances, customer charges on select schedules may need to be revised to reflect future changes to schedule-level distribution revenue. Should this occur, revised customer charges will never exceed the levels set here until otherwise revised by the Commission.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Settlement Agreement shall become effective among the Settling Parties on the date the last Settling Party executes the Settlement Agreement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Settlement Agreement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Agricultural Energy Consumers Association

By /s/
Dan Geis

Title: Asst. Executive Director

Date: 2/9/07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Building Owners and Managers Associations of
San Francisco, Greater Los Angeles, Orange County
and California (BOMA)

By: /s/
B. F. Roberts

Title: President, Economic Sciences Corp.
For BOMA

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California City-County Street Light Association

By /s/
Reed V. Schmidt

Title: Energy Economist

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Farm Bureau Federation

By /s/
Ronald Liebert

Title: Associate Counsel

Date: Feb. 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Large Energy Consumers Association

By: /s/
W. H. Booth

Title: Counsel

Date: 2/8/07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California League of Food Processors

By /s/
Rob Neenan

Title: Director of Regulatory Affairs

Date: February 9, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Manufacturers & Technology Association

By: /s/
Keith R. McCrea

Title: Attorney

Date: February 9, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Retailers Association

By: /s/
James Squeri

Title: Counsel

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Rice Millers

By /s/
Paul Kerkorian

Title: Representative

Date: 2-8-07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Solar Energy Industries Association

By: /s/
Les Nelson

Title: CAL SEIA

Date: Feb. 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Cogeneration Association of California

By: /s/
Nora Sheriff

Title: Attorney

Date: Feb. 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Direct Access Customer Coalition

By: /s/
Greg Klatt

Title: Counsel

Date: 2/9/07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Division of Ratepayer Advocates

By: /s/
Dana Appling

Title: Director

Date: 2/8/07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Energy Producers and Users Coalition

By: /s/
Nora Sheriff

Title: Attorney

Date: Feb. 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Energy Users Forum

By: /s/
Carolyn M. Kehrein

Title: Consultant

Date: February 7, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Federal Executive Agencies

By: /s/
Norman Furuta

Title: Associate Counsel

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Indicated Commercial Parties

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

By: /s/
Randall W. Keen

Title: Partner

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Pacific Gas and Electric Company

By: /s/
Dan Pease

Title: Manager, Electric Rates

Date: February 9, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

PV Now

By: /s/
Joseph Wiedman

Title: Attorney – PV Now

Date: 2/8/07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

The Utility Reform Network

By: /s/
Matthew Freedman

Title: Staff Attorney

Date: February 8, 2007

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Vote Solar

By: /s/
Greggory Wheatland

Title: Attorney

Date: 2-9-07

The undersigned represent that they are authorized to sign on behalf of the Party represented.

The Western Manufactured Housing
Communities Association

By: /s/
Edward Poole

Title: Attorney

Date: February 8, 2007

(END OF APPENDIX B)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON RESIDENTIAL RATE DESIGN ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Residential Rate Design Settlement Agreement (Settling Parties, Residential Settlement) agree on a mutually acceptable outcome to the residential rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This Residential Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses residential rate issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this Residential Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this Residential Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- California Solar Energy Industries Association (CAL SEIA)
- Division of Ratepayer Advocates (DRA)
- Pacific Gas and Electric Company (PG&E)
- PV Now (PV Now)
- The Utility Reform Network (TURN)
- Vote Solar

- The Western Manufactured Housing Communities Association (WMA)

III. SETTLEMENT CONDITIONS

This Residential Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on residential rate design, subject to the conditions set forth below:

1. This Residential Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This Residential Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.
2. This Residential Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Residential Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this Residential Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this Residential Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
5. This Residential Settlement may be amended or changed only by a written agreement signed by the Settling Parties.
6. The Settling Parties shall jointly request Commission approval of this Residential Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required,

comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the Residential Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the residential rate design agreed to herein. In the event the Commission rejects or modifies this Residential Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the

Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, the Settling Parties to this Residential Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. RESIDENTIAL SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the rate design for the residential class embodied in this Residential Settlement takes the revenue allocation reached for that class in the February 9 Settlement and ensures that it is fully recovered through residential rates in a manner that is just and reasonable, in the public interest, and that reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which is based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this Residential Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the residential class and will differ from the rates presented herein. However, these actual rates shall be based on the residential rate structure described below. Illustrative rates for the residential class are set forth in Exhibit A to this Residential Settlement.

The Settling Parties agree that all testimony served prior to the date of this Residential Settlement that addresses the issues resolved by this Residential Settlement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree that this Residential Settlement resolves all residential rate design issues in A.06-03-005.

VI. RESIDENTIAL RATE DESIGN SETTLEMENT TERMS

A. Total bundled residential California Alternate Rates for Energy (CARE) rates will remain unchanged subject to the provisions of the February 9 Settlement.

B. Residential baseline quantities shall be revised in accordance with PG&E's testimony, subject to the restrictions on charges to residential customers for usage up to 130 percent of baseline as provided by Assembly Bill AB 1X. The electric and gas target baseline quantities provided in Exhibit (PG&E-3), Table 3-2 shall be adopted. The parties agree to phase in baseline quantities, together with appropriate revenue neutral rate adjustments, beginning on May 1, 2008 for electric and April 1, 2008 for gas, subject to receiving a decision in this proceeding leaving adequate time for implementation. Phase in will continue in subsequent years as necessary on May 1 for electric and April 1 for gas until target quantities are achieved. Prior to implementing the change in baseline quantities described herein, residential sales and associated rates will be based on then currently effective baseline quantities.

C. In PG&E's 2003 GRC Phase 2 proceeding (A.04-06-024), PG&E, WMA, TURN and DRA, among others, filed a settlement agreement on May 13, 2005 (2003 Phase 2 Revenue Allocation Settlement), resolving revenue allocation and certain specific rate design issues raised in that proceeding. In Section V.4.f of the 2003 Phase 2 Revenue Allocation Settlement, the parties agreed, among other things, that (1) "the master-meter discount for electric Schedule ET-Mobilehome Park Service shall be fixed at $0.379 per space per day until the next applicable GRC Phase 2 proceeding"; (2) the "net master-meter discount for electric Schedule ES – Multifamily Service (for other than mobile home parks) shall be fixed at the current level or $0.10579 per unit per day… and shall be fixed at these levels until the next applicable GRC"; and (3) "[o]n or before July 1, 2007, PG&E shall update the data used to calculate the diversity benefit adjustment using sample metered data for directly metered mobile home parks, in consultation with WMA and TURN regarding the characteristics of the sample data, and shall submit a new diversity benefit study to the CPUC in PG&E's next GRC Phase 2 proceeding or in another rate design proceeding."

Since the autumn of 2005, PG&E, TURN and WMA have been working cooperatively to develop a new diversity benefit study, consistent with the terms of the 2003 Phase 2 Revenue Allocation Settlement. As of the date of this Residential Settlement, however, the diversity benefit study has not been completed. Rather than litigate issues related to the electric master meter discount in PG&E's 2007 GRC Phase2 proceeding, PG&E, WMA, TURN and DRA agree that the master meter discount for Schedules ET and ES agreed to in the 2003 Phase 2 Revenue Allocation Settlement should continue in place until a new electric master meter discount is adopted in another PG&E rate design proceeding, such as PG&E's next Biennial Cost Allocation Proceeding (BCAP) or the Electric Rate Design Window proceeding. PG&E, WMA, TURN and DRA further agree that the deadline for completing the new diversity benefit study should be extended by one month to August 1, 2007.

PG&E, WMA, TURN and DRA agree to work cooperatively to reach agreement on the appropriate new electric master meter discount, taking into account the results of the new diversity benefit study. If the parties reach agreement on a new electric master meter discount, they will memorialize the terms in a formal settlement agreement, which will be filed with the CPUC and subject to formal approval. Alternatively, if the parties do not reach agreement, PG&E will promptly file its proposal for a new electric master meter discount in a future rate design proceeding, such as PG&E's BCAP or Electric Rate Design Window proceeding.

D. Total bundled rates for usage up to 130 percent of baseline will not be changed so long as the rate restrictions of AB 1X are effective, subject only to the increase to total bundled non-CARE rates for usage up to 130 percent of baseline for the California Solar Initiative (CSI) as described in Item G below. While the rate restrictions of AB 1X are in effect, revenue increases to the residential class will be implemented as proportional changes to the generation surcharges in Tiers 3, 4 and 5 as required to collect the revenue allocated to the residential class. Revenue reductions to the residential class will be implemented by not changing rates for usage up to 130 percent of baseline, and by proportionally reducing generation surcharges in Tiers 3, 4 and 5 to ensure the proper revenue is collected from residential class.

E. Should a reduction to the residential class in excess of three percent be expected, PG&E will consult with DRA and TURN to determine the proper method of allocating that revenue between tiers, provided however, that rates for usage up to 130 percent of baseline shall not be reduced. Should DRA, TURN and PG&E be unable to agree on the method to allocate the revenue reduction between tiers, PG&E will implement the change in the manner described in Part D, above.

F. Distribution and generation rates for non-CARE rate schedules in the residential class shall be differentiated by tier. Distribution and generation revenue on non-CARE rate schedules shall be collected in each rate tier in the same proportion as the generation and distribution revenue is allocated to each rate schedule, prior to determining rates for the CSI as described in item G.

G. Changes to total rates charged to the first 130 percent of baseline usage have been calculated as a compromise of positions between the parties in consideration of Public Utilities Code Section 2851 (d) (2). The Settling Parties took into consideration the total CSI revenue requirement in 2007 and the methods used to set total residential rates in the past, the net incremental solar costs created by the implementation of new CSI revenue requirements, a reduction in revenue requirements for the Self Generation Incentive Program, the revised inter-class allocation methodology for CSI and SGIP costs contained in the February 9 settlement, and an appropriate methodology for spreading these costs among all rate tiers. Accordingly, the Settlement Parties agree to increase total non-CARE rates in each tier by the negotiated CSI rate. The CSI rate will be determined as an equal proportion of pre-CSI distribution revenue in each tier as required to collect the CSI revenue allocated to the non-CARE residential schedules. The CSI exemption for customers taking service on the Family Electric Rate Assistance (FERA) program will be applied as a percentage of each customer's distribution energy charges (excluding charges or credits for the rate reduction bond memorandum account). CSI discounts provided to FERA customers will be accrued in the FERA balancing account and collected from residential customer distribution rates in the Annual Electric True Up filing.

H. PG&E's proposal to revise the Minimum Average Rate Limiter (MARL) for residential master metered customers that receive a submeter discount shall be adopted as set forth in Exhibit (PG&E-3), Chapter 3F.

I. To comply with D.05-12-041, residential rates for CARE are designed to reflect the CARE discount (including the discount provided currently as distribution and the discount currently provided as generation) in distribution rates. The CARE surcharge is then designed to collect the amount of this discount as set forth in the February 9 Settlement. In this Residential Settlement, CARE distribution rates are set to minimize the case where CARE customers taking Direct Access (DA) and Community Choice Aggregation (CCA) service would receive a negative utility bill. This is accomplished on CARE rate schedules that are subject to a minimum charge by setting a negative distribution rate that has an absolute value no greater than the positive charges to be paid by these customers. The utility charge for DA and CCA customers taking service on master-meter CARE rate schedules or on Schedule EL-8 will be no less than zero.

J. Ongoing Time-of-Use (TOU) meter charges applicable to voluntary residential TOU rate schedules will no longer be applied as each customer's Advanced Meter Infrastructure (AMI) meter is installed and used for billing.

K. PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15 and 1-16, shall be adopted for DA and CCA service.

L. Schedules E-7 and EL-7 shall be closed to new enrollment on the date Schedules E-6 and EL-6 that result from this proceeding are implemented. The Settling Parties agree that the revised Schedules E-6 and EL-6 fulfill the requirements of Senate Bill (SB) 1, Public Utilities Code Section 2851 (a)(4), requiring "a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems…" This Settlement does not restrict parties from taking positions they deem appropriate in a subsequent proceeding that addresses time-variant rates, provided that prior to the next GRC Phase 2 proceeding, no Settling Party may argue that Schedules E-6 and EL-6 do not meet the SB-1 requirement for "a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems."

M. The Settling Parties agree that customers are required to take service on a TOU rate schedule in order to receive CSI incentives for installing solar systems. Accordingly, in addition to the TOU alternatives described above, the Settlement Parties agree to establish a time-of-use schedule for multifamily accounts currently eligible to take service under Schedules EM or EML. These new rate options would utilize the same rates and TOU periods established for Schedules E-6 and EL-6, but would be eligible for multiple baseline allowances. The applicable baseline allowances would be those adopted for Schedules EM and EML.

N. The Settling Parties agree that the Commission shall not require that customers taking service on submetered Schedules ET, ES, ESR or their CARE counterpart schedules take service on TOU options in order to receive CSI incentives. The Commission has not made TOU options available to these customers in the past and the Settling Parties agree that the submetering of tenants creates complications that cannot easily be addressed at this time.

O. Schedule E-9 is revised in accordance with the rates shown in Exhibit A. Further, the Settling Parties agree to clarify the applicability language in Schedule E9.

Replace the current text: "This experimental schedule applies to electric service to customers for whom Schedule E-1 applies and who refuel a low emission vehicle (LEV) at their premises. An LEV is either an electric vehicle (EV) or a natural gas vehicle (NGV)."

With the following clarification: "This experimental schedule applies to electric service to customers for whom Schedule E-1 applies and have a currently registered Motor Vehicle, as defined by the California Motor Vehicle Code, which is exclusively fueled with electricity (electric vehicle or EV) or natural gas (natural gas vehicle or NGV). Low Speed Electric Vehicles, as defined by the California Motor Vehicle Code, are not eligible for this rate option."

P. The illustrative rates shown in Exhibit A are developed to collect the same revenue allocated to the residential class that was used for the February 9 Settlement. The actual rates developed to implement this decision will vary based on the then current adopted revenue requirements.

Q. Timing of Rate Changes: Certain elements of this Residential Settlement require employee training and/or changes to PG&E systems beyond a normal change to a rate value. These changes include: (1) the FERA exemption in item (G); (2) the revision to MARL in item (H); (3) the application of a zero minimum charge and related CARE changes in item (I); (4) discontinuing the ongoing TOU meter charge in item (J); (5) revision of the franchise fee surcharge calculation in item (K); and (6) creating new multifamily TOU options as noted in item (M). These systems and program changes will be implemented by PG&E diligently as time permits and in a manner consistent with maintaining the secure, smooth operations of the systems involved. The Settling Parties recognize that some initiatives could take several months to implement.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this Residential Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Residential Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the Residential Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Residential Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Solar Energy Industries Association

By: /s/
Gary Gerber

Title: V.P.

Date: 3/15/07

Division of Ratepayer Advocates

By: /s/
Dana Appling

Title: Director

Date: 3/15/07

Pacific Gas and Electric Company

By: /s/
Dan Pease

Title: Manager, Electric Rates

Date: 3/16/07

PV Now

By: /s/
Joseph Wiedman

Title: Attorney

Date: 3/16/07

The Utility Reform Network

By: /s/
Staff Attorney

Title: Matt Freedman

Date: 3/16/07

Vote Solar

By: /s/
J. P. Ross

Title: Director of Programs

Date: 3/15/07

The Western Manufactured Housing
Communities Association

By: /s/
Edward Poole

Title: Attorney

Date: 3/14/07

PROPOSED GRC PH2 SETTLEMENT

E-1

		BUNDLED						DIRECT ACCESS					
		Est. 3/1/07 Total	Dist	PPP	Gen	Other	**Proposed Total**	Dist	PPP	DA CRS		Other	**Proposed Total**
Energy	T1	0.11430	$0.03745	$0.01048	$0.04624	$0.02126	**$0.11543**	$0.03745	$0.01048	$0.00810		$0.01306	**$0.06909**
	T2	0.12989	$0.04451	$0.01048	$0.05498	$0.02126	**$0.13124**	$0.04451	$0.01048	$0.00810		$0.01306	**$0.07615**
	T3	0.22723	$0.09273	$0.01048	$0.11494	$0.02126	**$0.23940**	$0.09273	$0.01048	$0.00810		$0.01306	**$0.12437**
	T4	0.31722	$0.13730	$0.01048	$0.17035	$0.02126	**$0.33939**	$0.13730	$0.01048	$0.00810		$0.01306	**$0.16894**
	T5	0.36438	$0.16066	$0.01048	$0.19940	$0.02126	**$0.39179**	$0.16066	$0.01048	$0.00810		$0.01306	**$0.19230**
MARL					$0.03678	$0.01214	**$0.04892**			$0.00810		$0.00394	**$0.01204**
Min Bill	$/mtr/mo	$4.50	$3.58	$0.14	$0.78	$0.00	**$4.50**	$3.58	$0.14				**$3.72**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810		$0.01272	**$0.02082**

EL-1

		BUNDLED						DIRECT ACCESS					
		Est. 3/1/07 Total	Dist	PPP	Gen	Other	**Proposed Total**	Dist	PPP	DA CRS	DA PCIA	Other	**Proposed Total**
Energy	T1	0.08316	($0.00205)	$0.00572	$0.06292	$0.01657	**$0.08316**	($0.00205)	$0.00572	$0.00351	($0.00010)	$0.01306	**$0.02014**
	T2	0.09563	($0.00205)	$0.00572	$0.07539	$0.01657	**$0.09563**	($0.00205)	$0.00572	$0.00351	($0.00010)	$0.01306	**$0.02014**
	T3	0.09563	($0.00205)	$0.00572	$0.07539	$0.01657	**$0.09563**	($0.00205)	$0.00572	$0.00351	($0.00010)	$0.01306	**$0.02014**
	T4	0.09563	($0.00205)	$0.00572	$0.07539	$0.01657	**$0.09563**	($0.00205)	$0.00572	$0.00351	($0.00010)	$0.01306	**$0.02014**
	T5	0.09563	($0.00205)	$0.00572	$0.07539	$0.01657	**$0.09563**	($0.00205)	$0.00572	$0.00351	($0.00010)	$0.01306	**$0.02014**
MARL					$0.04147	$0.00745	**$0.04892**			$0.00351	($0.00010)	$0.00394	**$0.00735**
Min Bill	$/mtr/mo	$3.60	$2.68	$0.07	$0.84	$0.00	**$3.60**	$2.68	$0.07				**$2.75**
	$/kWh				($0.01623)	$0.01623	**$0.00000**			$0.00351	($0.00010)	$0.01272	**$0.01613**

E-7

		BUNDLED Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	DIRECT ACCESS Dist	PPP	DA CRS	Other	Proposed Total
ENERGY												
Smr Peak	T1	0.29372	$0.09379	$0.01026	$0.17220	$0.02126	**$0.29752**	$0.09379	$0.01026	$0.00810	$0.01306	**$0.12521**
	T2	0.29372	$0.09379	$0.01026	$0.17220	$0.02126	**$0.29752**	$0.09379	$0.01026	$0.00810	$0.01306	**$0.12521**
	T3	0.39106	$0.13185	$0.01026	$0.24239	$0.02126	**$0.40576**	$0.13185	$0.01026	$0.00810	$0.01306	**$0.16327**
	T4	0.48105	$0.16703	$0.01026	$0.30727	$0.02126	**$0.50582**	$0.16703	$0.01026	$0.00810	$0.01306	**$0.19845**
	T5	0.52821	$0.18547	$0.01026	$0.34127	$0.02126	**$0.55827**	$0.18547	$0.01026	$0.00810	$0.01306	**$0.21689**
Smr Off-Peak	T1	0.08664	$0.01975	$0.01026	$0.03617	$0.02126	**$0.08744**	$0.01975	$0.01026	$0.00810	$0.01306	**$0.05117**
	T2	0.08664	$0.01975	$0.01026	$0.03617	$0.02126	**$0.08744**	$0.01975	$0.01026	$0.00810	$0.01306	**$0.05117**
	T3	0.18398	$0.05781	$0.01026	$0.10635	$0.02126	**$0.19569**	$0.05781	$0.01026	$0.00810	$0.01306	**$0.08923**
	T4	0.27397	$0.09299	$0.01026	$0.17123	$0.02126	**$0.29575**	$0.09299	$0.01026	$0.00810	$0.01306	**$0.12441**
	T5	0.32113	$0.11143	$0.01026	$0.20524	$0.02126	**$0.34819**	$0.11143	$0.01026	$0.00810	$0.01306	**$0.14285**
Smr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Wtr Peak	T1	0.11472	$0.02979	$0.01026	$0.05461	$0.02126	**$0.11593**	$0.02979	$0.01026	$0.00810	$0.01306	**$0.06121**
	T2	0.11472	$0.02979	$0.01026	$0.05461	$0.02126	**$0.11593**	$0.02979	$0.01026	$0.00810	$0.01306	**$0.06121**
	T3	0.21206	$0.06785	$0.01026	$0.12480	$0.02126	**$0.22417**	$0.06785	$0.01026	$0.00810	$0.01306	**$0.09927**
	T4	0.30205	$0.10303	$0.01026	$0.18968	$0.02126	**$0.32423**	$0.10303	$0.01026	$0.00810	$0.01306	**$0.13445**
	T5	0.34921	$0.12147	$0.01026	$0.22368	$0.02126	**$0.37668**	$0.12147	$0.01026	$0.00810	$0.01306	**$0.15289**
Wtr Off-Peak	T1	0.08966	$0.02083	$0.01026	$0.03815	$0.02126	**$0.09051**	$0.02083	$0.01026	$0.00810	$0.01306	**$0.05225**
	T2	0.08966	$0.02083	$0.01026	$0.03815	$0.02126	**$0.09051**	$0.02083	$0.01026	$0.00810	$0.01306	**$0.05225**
	T3	0.18700	$0.05889	$0.01026	$0.10834	$0.02126	**$0.19875**	$0.05889	$0.01026	$0.00810	$0.01306	**$0.09031**
	T4	0.27699	$0.09407	$0.01026	$0.17322	$0.02126	**$0.29881**	$0.09407	$0.01026	$0.00810	$0.01306	**$0.12549**
	T5	0.32415	$0.11251	$0.01026	$0.20722	$0.02126	**$0.35125**	$0.11251	$0.01026	$0.00810	$0.01306	**$0.14393**
Wtr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14		0.00	**$4.08**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810	$0.01272	**$0.02082**

EL-7

		BUNDLED Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	DIRECT ACCESS Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
ENERGY													
Smr Peak	T1	0.28372	($0.01809)	$0.01026	$0.27498	$0.01657	**$0.28372**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T2	0.28372	($0.01809)	$0.01026	$0.27498	$0.01657	**$0.28372**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T3	0.28372	($0.01809)	$0.01026	$0.27498	$0.01657	**$0.28372**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T4	0.28372	($0.01809)	$0.01026	$0.27498	$0.01657	**$0.28372**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T5	0.28372	($0.01809)	$0.01026	$0.27498	$0.01657	**$0.28372**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
Smr Off-Peak	T1	0.07664	($0.01809)	$0.01026	$0.06790	$0.01657	**$0.07664**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T2	0.07664	($0.01809)	$0.01026	$0.06790	$0.01657	**$0.07664**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T3	0.07664	($0.01809)	$0.01026	$0.06790	$0.01657	**$0.07664**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T4	0.07664	($0.01809)	$0.01026	$0.06790	$0.01657	**$0.07664**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T5	0.07664	($0.01809)	$0.01026	$0.06790	$0.01657	**$0.07664**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
Smr Baseline Credit		(0.01559)	($0.01559)				**($0.01559)**	($0.01559)					**($0.01559)**
Wtr Peak	T1	0.10472	($0.01809)	$0.01026	$0.09598	$0.01657	**$0.10472**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T2	0.10472	($0.01809)	$0.01026	$0.09598	$0.01657	**$0.10472**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T3	0.10472	($0.01809)	$0.01026	$0.09598	$0.01657	**$0.10472**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T4	0.10472	($0.01809)	$0.01026	$0.09598	$0.01657	**$0.10472**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T5	0.10472	($0.01809)	$0.01026	$0.09598	$0.01657	**$0.10472**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
Wtr Off-Peak	T1	0.07966	($0.01809)	$0.01026	$0.07092	$0.01657	**$0.07966**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T2	0.07966	($0.01809)	$0.01026	$0.07092	$0.01657	**$0.07966**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T3	0.07966	($0.01809)	$0.01026	$0.07092	$0.01657	**$0.07966**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T4	0.07966	($0.01809)	$0.01026	$0.07092	$0.01657	**$0.07966**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
	T5	0.07966	($0.01809)	$0.01026	$0.07092	$0.01657	**$0.07966**	($0.01809)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00864**
Wtr Baseline Credit		(0.01559)	($0.01559)				**($0.01559)**	($0.01559)					**($0.01559)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14			0.00	**$4.08**
	$/kWh				($0.01623)	$0.01623	**$0.00000**			$0.00351	($0.00010)	$0.01272	**$0.01613**

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BUNDLED

		Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total
ENERGY							
Summer	T1	0.11815	$0.01476	$0.01099	$0.07229	$0.02126	**$0.11930**
	T2	0.11815	$0.01476	$0.01099	$0.07229	$0.02126	**$0.11930**
	T3	0.21549	$0.03302	$0.01099	$0.16215	$0.02126	**$0.22742**
	T4	0.30548	$0.04990	$0.01099	$0.24521	$0.02126	**$0.32736**
	T5	0.35264	$0.05875	$0.01099	$0.28875	$0.02126	**$0.37975**
Winter	T1	0.07577	$0.00749	$0.01099	$0.03661	$0.02126	**$0.07635**
	T2	0.07577	$0.00749	$0.01099	$0.03661	$0.02126	**$0.07635**
	T3	0.17311	$0.02575	$0.01099	$0.12647	$0.02126	**$0.18447**
	T4	0.26310	$0.04263	$0.01099	$0.20954	$0.02126	**$0.28442**
	T5	0.31026	$0.05148	$0.01099	$0.25307	$0.02126	**$0.33680**
CUSTOMER	$/mtr/mo	$12.53	$12.53				**$12.53**

DIRECT ACCESS

		Dist	PPP	DA CRS		Other	Proposed Total
ENERGY							
Summer	T1	$0.01476	$0.01099	$0.00810		$0.01306	**$0.04691**
	T2	$0.01476	$0.01099	$0.00810		$0.01306	**$0.04691**
	T3	$0.03302	$0.01099	$0.00810		$0.01306	**$0.06517**
	T4	$0.04990	$0.01099	$0.00810		$0.01306	**$0.08205**
	T5	$0.05875	$0.01099	$0.00810		$0.01306	**$0.09090**
Winter	T1	$0.00749	$0.01099	$0.00810		$0.01306	**$0.03964**
	T2	$0.00749	$0.01099	$0.00810		$0.01306	**$0.03964**
	T3	$0.02575	$0.01099	$0.00810		$0.01306	**$0.05790**
	T4	$0.04263	$0.01099	$0.00810		$0.01306	**$0.07478**
	T5	$0.05148	$0.01099	$0.00810		$0.01306	**$0.08363**
CUSTOMER	$/mtr/mo	$12.53					**$12.53**

EL-8

BUNDLED

		Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total
ENERGY							
Summer	T1	0.08624	($0.10095)	$0.00623	$0.16439	$0.01657	**$0.08624**
	T2	0.08624	($0.10095)	$0.00623	$0.16439	$0.01657	**$0.08624**
	T3	0.08624	($0.10095)	$0.00623	$0.16439	$0.01657	**$0.08624**
	T4	0.08624	($0.10095)	$0.00623	$0.16439	$0.01657	**$0.08624**
	T5	0.08624	($0.10095)	$0.00623	$0.16439	$0.01657	**$0.08624**
Winter	T1	0.05234	($0.10095)	$0.00623	$0.13049	$0.01657	**$0.05234**
	T2	0.05234	($0.10095)	$0.00623	$0.13049	$0.01657	**$0.05234**
	T3	0.05234	($0.10095)	$0.00623	$0.13049	$0.01657	**$0.05234**
	T4	0.05234	($0.10095)	$0.00623	$0.13049	$0.01657	**$0.05234**
	T5	0.05234	($0.10095)	$0.00623	$0.13049	$0.01657	**$0.05234**
CUSTOMER	$/mtr/mo	$10.02	$10.02				**$10.02**

DIRECT ACCESS

		Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
ENERGY							
Summer	T1	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T2	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T3	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T4	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T5	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
Winter	T1	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T2	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T3	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T4	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
	T5	($0.10095)	$0.00623	$0.00351	($0.00010)	$0.01306	**($0.07825)**
CUSTOMER	$/mtr/mo	$10.02					**$10.02**

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		BUNDLED						DIRECT ACCESS					
		Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	Dist	PPP	DA CRS		Other	Proposed Total
ENERGY													
Smr Peak	Tier 1	0.04962	$0.11377	$0.01051	$0.14901	$0.02126	**$0.29455**	$0.11377	$0.01051	$0.00810		$0.01306	**$0.14544**
	Tier 2	0.06521	$0.12061	$0.01051	$0.15798	$0.02126	**$0.31036**	$0.12061	$0.01051	$0.00810		$0.01306	**$0.15228**
	Tier 3	0.16255	$0.16731	$0.01051	$0.21945	$0.02126	**$0.41852**	$0.16731	$0.01051	$0.00810		$0.01306	**$0.19897**
	Tier 4	0.25254	$0.21047	$0.01051	$0.27626	$0.02126	**$0.51850**	$0.21047	$0.01051	$0.00810		$0.01306	**$0.24213**
	Tier 5	0.29970	$0.23309	$0.01051	$0.30604	$0.02126	**$0.57090**	$0.23309	$0.01051	$0.00810		$0.01306	**$0.26476**
Smr Pt Peak	Tier 1	(0.04729)	$0.04826	$0.01051	$0.06314	$0.02126	**$0.14317**	$0.04826	$0.01051	$0.00810		$0.01306	**$0.07993**
	Tier 2	(0.03170)	$0.05510	$0.01051	$0.07210	$0.02126	**$0.15897**	$0.05510	$0.01051	$0.00810		$0.01306	**$0.08677**
	Tier 3	0.06564	$0.10179	$0.01051	$0.13357	$0.02126	**$0.26713**	$0.10179	$0.01051	$0.00810		$0.01306	**$0.13346**
	Tier 4	0.15563	$0.14496	$0.01051	$0.19039	$0.02126	**$0.36711**	$0.14496	$0.01051	$0.00810		$0.01306	**$0.17662**
	Tier 5	0.20279	$0.16758	$0.01051	$0.22017	$0.02126	**$0.41951**	$0.16758	$0.01051	$0.00810		$0.01306	**$0.19924**
Smr Off Peak	Tier 1	(0.06485)	$0.02186	$0.01051	$0.02853	$0.02126	**$0.08215**	$0.02186	$0.01051	$0.00810		$0.01306	**$0.05352**
	Tier 2	(0.04926)	$0.02869	$0.01051	$0.03749	$0.02126	**$0.09795**	$0.02869	$0.01051	$0.00810		$0.01306	**$0.06036**
	Tier 3	0.04808	$0.07539	$0.01051	$0.09896	$0.02126	**$0.20611**	$0.07539	$0.01051	$0.00810		$0.01306	**$0.10705**
	Tier 4	0.13807	$0.11855	$0.01051	$0.15578	$0.02126	**$0.30609**	$0.11855	$0.01051	$0.00810		$0.01306	**$0.15022**
	Tier 5	0.18523	$0.14117	$0.01051	$0.18555	$0.02126	**$0.35849**	$0.14117	$0.01051	$0.00810		$0.01306	**$0.17284**
Wtr Pt Peak	Tier 1	(0.03490)	$0.02872	$0.01051	$0.03753	$0.02126	**$0.09802**	$0.02872	$0.01051	$0.00810		$0.01306	**$0.06039**
	Tier 2	(0.01931)	$0.03556	$0.01051	$0.04649	$0.02126	**$0.11382**	$0.03556	$0.01051	$0.00810		$0.01306	**$0.06723**
	Tier 3	0.07803	$0.08225	$0.01051	$0.10796	$0.02126	**$0.22198**	$0.08225	$0.01051	$0.00810		$0.01306	**$0.11392**
	Tier 4	0.16802	$0.12542	$0.01051	$0.16478	$0.02126	**$0.32196**	$0.12542	$0.01051	$0.00810		$0.01306	**$0.15708**
	Tier 5	0.21518	$0.14804	$0.01051	$0.19456	$0.02126	**$0.37436**	$0.14804	$0.01051	$0.00810		$0.01306	**$0.17971**
Wtr Off Peak	Tier 1	(0.05861)	$0.02359	$0.01051	$0.03080	$0.02126	**$0.08616**	$0.02359	$0.01051	$0.00810		$0.01306	**$0.05526**
	Tier 2	(0.04302)	$0.03043	$0.01051	$0.03977	$0.02126	**$0.10196**	$0.03043	$0.01051	$0.00810		$0.01306	**$0.06210**
	Tier 3	0.05432	$0.07712	$0.01051	$0.10123	$0.02126	**$0.21012**	$0.07712	$0.01051	$0.00810		$0.01306	**$0.10879**
	Tier 4	0.14431	$0.12029	$0.01051	$0.15805	$0.02126	**$0.31010**	$0.12029	$0.01051	$0.00810		$0.01306	**$0.15195**
	Tier 5	0.19147	$0.14291	$0.01051	$0.18783	$0.02126	**$0.36251**	$0.14291	$0.01051	$0.00810		$0.01306	**$0.17457**
Min Bill	$/mtr/mo	$4.50	$3.58	$0.14	$0.78	$0.00	**$4.50**	$3.58	$0.14			0.00	**$3.72**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810		$0.01272	**$0.02082**

EL-6

		BUNDLED						DIRECT ACCESS					
		Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
ENERGY													
Smr Peak	Tier 1	0.06161	($0.00538)	$0.00575	$0.19303	$0.01657	**$0.20996**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 2	0.07408	($0.00538)	$0.00575	$0.20550	$0.01657	**$0.22243**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 3	0.07691	($0.00538)	$0.00575	$0.20550	$0.01657	**$0.22243**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 4	0.07951	($0.00538)	$0.00575	$0.20550	$0.01657	**$0.22243**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 5	0.08087	($0.00538)	$0.00575	$0.20550	$0.01657	**$0.22243**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
Smr Pt Peak	Tier 1	(0.03530)	($0.00538)	$0.00575	$0.08544	$0.01657	**$0.10237**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 2	(0.02283)	($0.00538)	$0.00575	$0.09791	$0.01657	**$0.11484**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 3	(0.02000)	($0.00538)	$0.00575	$0.09791	$0.01657	**$0.11484**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 4	(0.01740)	($0.00538)	$0.00575	$0.09791	$0.01657	**$0.11484**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 5	(0.01604)	($0.00538)	$0.00575	$0.09791	$0.01657	**$0.11484**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
Smr Off Peak	Tier 1	(0.05286)	($0.00538)	$0.00575	$0.04207	$0.01657	**$0.05900**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 2	(0.04039)	($0.00538)	$0.00575	$0.05454	$0.01657	**$0.07147**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 3	(0.03756)	($0.00538)	$0.00575	$0.05454	$0.01657	**$0.07147**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 4	(0.03496)	($0.00538)	$0.00575	$0.05454	$0.01657	**$0.07147**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 5	(0.03360)	($0.00538)	$0.00575	$0.05454	$0.01657	**$0.07147**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
Wtr Pt Peak	Tier 1	(0.02291)	($0.00538)	$0.00575	$0.05334	$0.01657	**$0.07028**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 2	(0.01044)	($0.00538)	$0.00575	$0.06581	$0.01657	**$0.08275**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 3	(0.00761)	($0.00538)	$0.00575	$0.06581	$0.01657	**$0.08275**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 4	(0.00501)	($0.00538)	$0.00575	$0.06581	$0.01657	**$0.08275**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 5	(0.00365)	($0.00538)	$0.00575	$0.06581	$0.01657	**$0.08275**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
Wtr Off Peak	Tier 1	(0.04662)	($0.00538)	$0.00575	$0.04492	$0.01657	**$0.06185**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 2	(0.03415)	($0.00538)	$0.00575	$0.05739	$0.01657	**$0.07432**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 3	(0.03132)	($0.00538)	$0.00575	$0.05739	$0.01657	**$0.07432**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 4	(0.02872)	($0.00538)	$0.00575	$0.05739	$0.01657	**$0.07432**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
	Tier 5	(0.02736)	($0.00538)	$0.00575	$0.05739	$0.01657	**$0.07432**	($0.00538)	$0.00575	$0.00351	($0.00010)	$0.01306	**$0.01684**
Min Bill	$/mtr/mo	$3.60	$2.68	$0.07	$0.85	$0.00	**$3.60**	$2.68	$0.07			0.00	**$2.75**
	$/kWh				($0.01623)	$0.01623	**$0.00000**			$0.00351	($0.00010)	$0.01272	**$0.01613**

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		BUNDLED Est. 3/1/07 Total	BUNDLED Dist	BUNDLED PPP	BUNDLED Gen	BUNDLED Other	BUNDLED Proposed Total	DIRECT ACCESS Dist	DIRECT ACCESS PPP	DIRECT ACCESS DA CRS	DIRECT ACCESS Other	DIRECT ACCESS Proposed Total
ENERGY												
Smr Peak	T1	0.32260	$0.10412	$0.01026	$0.19117	$0.02126	**$0.32681**	$0.10412	$0.01026	$0.00810	$0.01306	**$0.13554**
	T2	0.32260	$0.10412	$0.01026	$0.19117	$0.02126	**$0.32681**	$0.10412	$0.01026	$0.00810	$0.01306	**$0.13554**
	T3	0.41994	$0.14218	$0.01026	$0.26136	$0.02126	**$0.43506**	$0.14218	$0.01026	$0.00810	$0.01306	**$0.17360**
	T4	0.50993	$0.17736	$0.01026	$0.32624	$0.02126	**$0.53512**	$0.17736	$0.01026	$0.00810	$0.01306	**$0.20878**
	T5	0.55709	$0.19580	$0.01026	$0.36024	$0.02126	**$0.58756**	$0.19580	$0.01026	$0.00810	$0.01306	**$0.22722**
Smr Off-Peak	T1	0.08248	$0.01826	$0.01026	$0.03344	$0.02126	**$0.08322**	$0.01826	$0.01026	$0.00810	$0.01306	**$0.04968**
	T2	0.08248	$0.01826	$0.01026	$0.03344	$0.02126	**$0.08322**	$0.01826	$0.01026	$0.00810	$0.01306	**$0.04968**
	T3	0.17982	$0.05632	$0.01026	$0.10362	$0.02126	**$0.19146**	$0.05632	$0.01026	$0.00810	$0.01306	**$0.08774**
	T4	0.26981	$0.09150	$0.01026	$0.16850	$0.02126	**$0.29152**	$0.09150	$0.01026	$0.00810	$0.01306	**$0.12292**
	T5	0.31697	$0.10994	$0.01026	$0.20250	$0.02126	**$0.34397**	$0.10994	$0.01026	$0.00810	$0.01306	**$0.14136**
Smr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Wtr Peak	T1	0.11393	$0.02951	$0.01026	$0.05410	$0.02126	**$0.11512**	$0.02951	$0.01026	$0.00810	$0.01306	**$0.06093**
	T2	0.11393	$0.02951	$0.01026	$0.05410	$0.02126	**$0.11512**	$0.02951	$0.01026	$0.00810	$0.01306	**$0.06093**
	T3	0.21127	$0.06757	$0.01026	$0.12428	$0.02126	**$0.22337**	$0.06757	$0.01026	$0.00810	$0.01306	**$0.09899**
	T4	0.30126	$0.10275	$0.01026	$0.18916	$0.02126	**$0.32343**	$0.10275	$0.01026	$0.00810	$0.01306	**$0.13417**
	T5	0.34842	$0.12119	$0.01026	$0.22316	$0.02126	**$0.37587**	$0.12119	$0.01026	$0.00810	$0.01306	**$0.15261**
Wtr Off-Peak	T1	0.08974	$0.02086	$0.01026	$0.03820	$0.02126	**$0.09058**	$0.02086	$0.01026	$0.00810	$0.01306	**$0.05228**
	T2	0.08974	$0.02086	$0.01026	$0.03820	$0.02126	**$0.09058**	$0.02086	$0.01026	$0.00810	$0.01306	**$0.05228**
	T3	0.18708	$0.05892	$0.01026	$0.10839	$0.02126	**$0.19883**	$0.05892	$0.01026	$0.00810	$0.01306	**$0.09034**
	T4	0.27707	$0.09410	$0.01026	$0.17327	$0.02126	**$0.29889**	$0.09410	$0.01026	$0.00810	$0.01306	**$0.12552**
	T5	0.32423	$0.11254	$0.01026	$0.20727	$0.02126	**$0.35133**	$0.11254	$0.01026	$0.00810	$0.01306	**$0.14396**
Wtr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14		0.00	**$4.08**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810	$0.01272	**$0.02082**

EL-A7

		BUNDLED Est. 3/1/07 Total	BUNDLED Dist	BUNDLED PPP	BUNDLED Gen	BUNDLED Other	BUNDLED Proposed Total	DIRECT ACCESS Dist	DIRECT ACCESS PPP	DIRECT ACCESS DA CRS	DIRECT ACCESS DA PCIA	DIRECT ACCESS Other	DIRECT ACCESS Proposed Total
ENERGY													
Smr Peak	T1	0.31260	($0.01978)	$0.01026	$0.30555	$0.01657	**$0.31260**	($0.01978)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00695**
	T2	0.31260	($0.03537)	$0.01026	$0.32114	$0.01657	**$0.31260**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T3	0.31260	($0.03537)	$0.01026	$0.32114	$0.01657	**$0.31260**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T4	0.31260	($0.03537)	$0.01026	$0.32114	$0.01657	**$0.31260**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T5	0.31260	($0.03537)	$0.01026	$0.32114	$0.01657	**$0.31260**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
Smr Off-Peak	T1	0.07248	($0.01978)	$0.01026	$0.06543	$0.01657	**$0.07248**	($0.01978)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00695**
	T2	0.07248	($0.03537)	$0.01026	$0.08102	$0.01657	**$0.07248**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T3	0.07248	($0.03537)	$0.01026	$0.08102	$0.01657	**$0.07248**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T4	0.07248	($0.03537)	$0.01026	$0.08102	$0.01657	**$0.07248**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T5	0.07248	($0.03537)	$0.01026	$0.08102	$0.01657	**$0.07248**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
Smr Baseline Credit		(0.01559)	($0.01559)				**($0.01559)**	($0.01559)					**($0.01559)**
Wtr Peak	T1	0.10393	($0.01978)	$0.01026	$0.09688	$0.01657	**$0.10393**	($0.01978)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00695**
	T2	0.10393	($0.03537)	$0.01026	$0.11247	$0.01657	**$0.10393**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T3	0.10393	($0.03537)	$0.01026	$0.11247	$0.01657	**$0.10393**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T4	0.10393	($0.03537)	$0.01026	$0.11247	$0.01657	**$0.10393**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T5	0.10393	($0.03537)	$0.01026	$0.11247	$0.01657	**$0.10393**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
Wtr Off-Peak	T1	0.07974	($0.01978)	$0.01026	$0.07269	$0.01657	**$0.07974**	($0.01978)	$0.01026	$0.00351	($0.00010)	$0.01306	**$0.00695**
	T2	0.07974	($0.03537)	$0.01026	$0.08828	$0.01657	**$0.07974**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T3	0.07974	($0.03537)	$0.01026	$0.08828	$0.01657	**$0.07974**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T4	0.07974	($0.03537)	$0.01026	$0.08828	$0.01657	**$0.07974**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
	T5	0.07974	($0.03537)	$0.01026	$0.08828	$0.01657	**$0.07974**	($0.03537)	$0.01026	$0.00351	($0.00010)	$0.01306	**($0.00864)**
Wtr Baseline Credit		(0.01559)	($0.01559)				**($0.01559)**	($0.01559)					**($0.01559)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14			0.00	**$4.08**
	$/kWh				($0.01623)	$0.01623	**$0.00000**			$0.00351	($0.00010)	$0.01272	**$0.01613**

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		BUNDLED Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	DIRECT ACCESS Dist	PPP	DA CRS	Other	Proposed Total
ENERGY												
Smr Peak	T1	0.28368	$0.09020	$0.01026	$0.16561	$0.02126	**$0.28733**	$0.09020	$0.01026	$0.00810	$0.01306	**$0.12162**
	T2	0.28368	$0.09020	$0.01026	$0.16561	$0.02126	**$0.28733**	$0.09020	$0.01026	$0.00810	$0.01306	**$0.12162**
	T3	0.38102	$0.12826	$0.01026	$0.23579	$0.02126	**$0.39558**	$0.12826	$0.01026	$0.00810	$0.01306	**$0.15968**
	T4	0.47101	$0.16344	$0.01026	$0.30067	$0.02126	**$0.49563**	$0.16344	$0.01026	$0.00810	$0.01306	**$0.19486**
	T5	0.51817	$0.18188	$0.01026	$0.33468	$0.02126	**$0.54808**	$0.18188	$0.01026	$0.00810	$0.01306	**$0.21330**
Smr Pt Peak	T1	0.10395	$0.02594	$0.01026	$0.04754	$0.02126	**$0.10500**	$0.02594	$0.01026	$0.00810	$0.01306	**$0.05736**
	T2	0.10395	$0.02594	$0.01026	$0.04754	$0.02126	**$0.10500**	$0.02594	$0.01026	$0.00810	$0.01306	**$0.05736**
	T3	0.20129	$0.06400	$0.01026	$0.11773	$0.02126	**$0.21325**	$0.06400	$0.01026	$0.00810	$0.01306	**$0.09542**
	T4	0.29128	$0.09918	$0.01026	$0.18260	$0.02126	**$0.31330**	$0.09918	$0.01026	$0.00810	$0.01306	**$0.13060**
	T5	0.33844	$0.11762	$0.01026	$0.21661	$0.02126	**$0.36575**	$0.11762	$0.01026	$0.00810	$0.01306	**$0.14904**
Smr Off-Peak	T1	0.04965	$0.00653	$0.01026	($0.00399)	$0.02126	**$0.03406**	$0.00653	$0.01026	$0.00810	$0.01306	**$0.03795**
	T2	0.04965	$0.00653	$0.01026	$0.01160	$0.02126	**$0.04965**	$0.00653	$0.01026	$0.00810	$0.01306	**$0.03795**
	T3	0.14699	$0.04459	$0.01026	$0.02390	$0.02126	**$0.10000**	$0.04459	$0.01026	$0.00810	$0.01306	**$0.07600**
	T4	0.23698	$0.07977	$0.01026	$0.03471	$0.02126	**$0.14600**	$0.07977	$0.01026	$0.00810	$0.01306	**$0.11119**
	T5	0.28414	$0.09821	$0.01026	$0.05528	$0.02126	**$0.18500**	$0.09821	$0.01026	$0.00810	$0.01306	**$0.12962**
Smr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Wtr Pt Peak	T1	0.10383	$0.02590	$0.01026	$0.04746	$0.02126	**$0.10488**	$0.02590	$0.01026	$0.00810	$0.01306	**$0.05732**
	T2	0.10383	$0.02590	$0.01026	$0.04746	$0.02126	**$0.10488**	$0.02590	$0.01026	$0.00810	$0.01306	**$0.05732**
	T3	0.20117	$0.06396	$0.01026	$0.11765	$0.02126	**$0.21312**	$0.06396	$0.01026	$0.00810	$0.01306	**$0.09538**
	T4	0.29116	$0.09914	$0.01026	$0.18252	$0.02126	**$0.31318**	$0.09914	$0.01026	$0.00810	$0.01306	**$0.13056**
	T5	0.33832	$0.11758	$0.01026	$0.21653	$0.02126	**$0.36562**	$0.11758	$0.01026	$0.00810	$0.01306	**$0.14900**
Wtr Off-Peak	T1	0.05795	$0.00949	$0.01026	$0.00135	$0.02126	**$0.04236**	$0.00949	$0.01026	$0.00810	$0.01306	**$0.04091**
	T2	0.05795	$0.00949	$0.01026	$0.01694	$0.02126	**$0.05795**	$0.00949	$0.01026	$0.00810	$0.01306	**$0.04091**
	T3	0.15529	$0.04755	$0.01026	$0.02093	$0.02126	**$0.10000**	$0.04755	$0.01026	$0.00810	$0.01306	**$0.07897**
	T4	0.24528	$0.08273	$0.01026	$0.03175	$0.02126	**$0.14600**	$0.08273	$0.01026	$0.00810	$0.01306	**$0.11415**
	T5	0.29244	$0.10117	$0.01026	$0.05231	$0.02126	**$0.18500**	$0.10117	$0.01026	$0.00810	$0.01306	**$0.13259**
Wtr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)				**($0.01582)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14		$0.00	**$4.08**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810	$0.01272	**$0.02082**

E-9B

		BUNDLED Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total	DIRECT ACCESS Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
ENERGY													
Smr Peak	T1	0.27967	$0.08877	$0.01026	$0.16297	$0.02126	**$0.28326**	$0.08877	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.12009**
	T2	0.27967	$0.08877	$0.01026	$0.16297	$0.02126	**$0.28326**	$0.08877	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.12009**
	T3	0.37701	$0.12683	$0.01026	$0.23316	$0.02126	**$0.39151**	$0.12683	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.15815**
	T4	0.46700	$0.16201	$0.01026	$0.29804	$0.02126	**$0.49157**	$0.16201	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.19333**
	T5	0.51416	$0.18045	$0.01026	$0.33204	$0.02126	**$0.54401**	$0.18045	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.21177**
Smr Pt Peak	T1	0.09994	$0.02451	$0.01026	$0.04491	$0.02126	**$0.10093**	$0.02451	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.05583**
	T2	0.09994	$0.02451	$0.01026	$0.04491	$0.02126	**$0.10093**	$0.02451	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.05583**
	T3	0.19728	$0.06257	$0.01026	$0.11509	$0.02126	**$0.20918**	$0.06257	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.09389**
	T4	0.28727	$0.09775	$0.01026	$0.17997	$0.02126	**$0.30924**	$0.09775	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.12907**
	T5	0.33443	$0.11619	$0.01026	$0.21397	$0.02126	**$0.36168**	$0.11619	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.14750**
Smr Off-Peak	T1	0.05616	$0.00885	$0.01026	$0.01615	$0.02126	**$0.05652**	$0.00885	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.04017**
	T2	0.05616	$0.00885	$0.01026	$0.01615	$0.02126	**$0.05652**	$0.00885	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.04017**
	T3	0.15350	$0.04691	$0.01026	$0.08633	$0.02126	**$0.16476**	$0.04691	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.07823**
	T4	0.24349	$0.08209	$0.01026	$0.15121	$0.02126	**$0.26482**	$0.08209	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.11341**
	T5	0.29065	$0.10053	$0.01026	$0.18521	$0.02126	**$0.31726**	$0.10053	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.13185**
Smr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)					**($0.01582)**
Wtr Peak	T1	0.10027	$0.02463	$0.01026	$0.04512	$0.02126	**$0.10127**	$0.02463	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.05594**
	T2	0.10027	$0.02463	$0.01026	$0.04512	$0.02126	**$0.10127**	$0.02463	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.05594**
	T3	0.19761	$0.04687	$0.01026	$0.13112	$0.02126	**$0.20951**	$0.04687	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.07819**
	T4	0.28760	$0.08205	$0.01026	$0.19600	$0.02126	**$0.30957**	$0.08205	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.11337**
	T5	0.33476	$0.10049	$0.01026	$0.23001	$0.02126	**$0.36201**	$0.10049	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.13181**
Wtr Off-Peak	T1	0.06378	$0.01158	$0.01026	$0.02115	$0.02126	**$0.06425**	$0.01158	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.04290**
	T2	0.06378	$0.01158	$0.01026	$0.02115	$0.02126	**$0.06425**	$0.01158	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.04290**
	T3	0.16112	$0.04964	$0.01026	$0.09134	$0.02126	**$0.17249**	$0.04964	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.08096**
	T4	0.25111	$0.08482	$0.01026	$0.15622	$0.02126	**$0.27255**	$0.08482	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.11614**
	T5	0.29827	$0.10326	$0.01026	$0.19022	$0.02126	**$0.32500**	$0.10326	$0.01026	$0.00810	($0.00010)	$0.01306	**$0.13458**
Wtr Baseline Credit		(0.01559)	($0.01582)				**($0.01582)**	($0.01582)					**($0.01582)**
Min Bill	$/mtr/mo	$4.50	$3.94	$0.14	$0.42	$0.00	**$4.50**	$3.94	$0.14			$0.00	**$4.08**
	$/kWh				($0.02092)	$0.02092	**$0.00000**			$0.00810	($0.00010)	$0.01272	**$0.02072**

(END OF APPENDIX C)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON STREETLIGHT RATE DESIGN ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Streetlight Rate Design Settlement Agreement (Settling Parties, Streetlight Settlement) agree on a mutually acceptable outcome to the streetlight rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This Streetlight Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses streetlight rate design issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this Streetlight Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this Streetlight Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- California City-County Street Light Association (CAL-SLA)
- Pacific Gas and Electric Company (PG&E)

III. SETTLEMENT CONDITIONS

This Streetlight Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on streetlight rate design, subject to the conditions set forth below:

1. This Streetlight Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or

written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This Streetlight Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.

2. This Streetlight Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Streetlight Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

3. The Settling Parties agree that this Streetlight Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

4. The Settling Parties agree that no provision of this Streetlight Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.

5. This Streetlight Settlement may be amended or changed only by a written agreement signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this Streetlight Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the Streetlight Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the streetlight rate design agreed to herein. In the event the Commission rejects or modifies this Streetlight Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping

Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, on March 15 parties to this Streetlight Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. STREETLIGHT SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of rate design for the streetlight class is to take the revenue allocation reached for that class in the February 9 Settlement and ensure that it is fully recovered through streetlight rates, including streetlight non-energy rates, in a manner that is just and reasonable, in the public interest, and reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which are based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this Streetlight Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the streetlight class and will differ from the rates presented herein. However, these actual rates shall be based on the streetlight energy rate structure described below.

Illustrative energy rates for Schedules LS-1, LS-2, LS-3 and OL-1 are set forth in Exhibit A to this Streetlight Settlement. Final non-energy rates for Schedules LS-1, LS-2, OL-1, and the City and County of San Francisco are set forth in Exhibits A and B. The terms of this Settlement Agreement are reflected in draft tariffs, as appropriate, and are attached to this Streetlight Settlement as Exhibit C (Schedule LS-1), Exhibit D (Schedule LS-2), Exhibit E (Schedule LS-3), and Exhibit F (Schedule TC-1).

The Settling Parties agree that all testimony served prior to the date of this Streetlight Settlement that addresses the issues resolved by this Streetlight Settlement should be admitted into evidence without cross-examination by the Settling Parties. The Settling Parties further agree that this Streetlight Settlement resolves all streetlight issues in A.06-03-005.

VI. STREETLIGHT SETTLEMENT TERMS

A. Streetlight Non-Energy Rates: The Settling Parties agree to the non-energy streetlight rates set forth in Exhibits A and B to this Streetlight Settlement.

B. Rate Design for Schedules LS-1 and LS-2: The Settling Parties agree to the use of the following formula to calculate the energy charge for streetlights:

((Lamp wattage + ballast wattage) x 4,100 hours/ 12 months/1000) x streetlight energy rate per kilowatthour (kWh)

Draft tariffs reflecting the implementation of the formula, including ballast factors, are provided in Exhibits C and D.

C. Wattage Limitation for Schedule LS-2: The Settling Parties agree to an upper-most limit of 150 watts of non-conforming load on customer owned streetlight circuits. This upper limit on allowable wattage for non-conforming load is based on and will accommodate current governmental agencies interest in low wattage connections with limited energy demand. The Settling Parties agree to the definition of non-conforming load as set forth in Condition 3(f) of the draft Schedule LS-2 tariff attached as Exhibit D.

D. Traffic Control Rate Schedule: The Settling Parties agree to retain the name Schedule TC-1, Traffic Control Service.

E. The Settling Parties further agree to the following streetlight rate design matters as set forth in PG&E's direct testimony. Associated tariff changes are set forth in draft tariffs attached to this Settlement Agreement as Exhibits C through F.

- The Schedule TC-1 customer charge will be set at the proposed level for single phase service under Schedule A-1. Energy rates are then determined residually such that they do not vary seasonally by function or in total.[1]
- The Schedule LS-3 customer charge will increase from $3 per month to $6 per month, expressed as a daily equivalent. The energy rate for Schedule LS-3 is set equal to the energy rate established for LS-1 and LS-2 and does not vary seasonally by function or total.
- On January 1 of each year following a decision in A.06-03-005, rates for the City and Count of San Francisco street lights on LS-1 or LS-2 or equivalent will be adjusted until the rates are set at the full cost, or until this issue is addressed and decided in a future GRC Phase 2 proceeding, whichever comes first. Final non-energy charges for City and County of

[1] Revenue allocation for Schedule TC-1 will be addressed as part of the Small Light and Power Rate Design Settlement.

San Francisco are shown in Exhibit B to this Streetlight Settlement.

- Eligibility for Schedule TC-1 will be revised to include general service loads on traffic control circuits whose energy requirements are constant over time (i.e. load that consumes energy at the same rate 24 hours a day, seven days a week) or are restricted to night-time use.
- Schedule TC-1 Condition 3 and Schedule LS-3 Condition 3 will be simplified by establishing annually an average allowance applicable to all customers. The allowances will be calculated using the average distribution revenue in the same manner as described in Application 10-05-016, testimony of Jamie Randolph, Chapter 2, pages 2-7 to 2-10.
- Schedule LS-1 Condition 13, Schedule LS-2 Condition 9, Schedule TC-1 Condition 6, and Schedule LS-3 Condition 6 shall be revised to allow installation of certain infrastructure required by local authorities in advance of actual subdivision work and bona fide loads. Payment and refund provisions will revert to the payment and refund provisions of Electric Rule 15.
- Schedule LS-1 Condition 9 will be amended to address attachments to street light poles for civic purposes. The appurtenances conditioned on a separate license agreement.
- Schedule LS-2 will only be applicable to governmental agencies. Schedule LS-2, Rate Class B, will be eliminated. Customers currently on Schedule LS-2, Rate Class B, will be allowed to choose Rate Class A or Rate Class C. Where the customer makes no choice, the customer will be placed on Rate Class C.
- Schedule LS-1 and Schedule LS-3 applicability will be expanded to allow streetlights in private areas to be served under these two schedules.
- Schedule LS-2 Condition 8 will be revised to reflect the elimination of Rate

Class B.

- Schedule LS-2 Condition 13 will be revised to eliminate the requirement that customers provide an inventory list of street lights.
- Schedule LS-1 Condition 3 and Schedule LS-2 Condition 7 will be revised to allow 24 hour operations.
- PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15, 1-16, shall be adopted for direct access and community choice aggregation service.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this Streetlight Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Streetlight Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the Streetlight Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Streetlight Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California City-County Street Light Association

By: /s/

Title: Energy Economist
Reed Schmidt

Date: 3/15/06

Pacific Gas and Electric Company

By: /s/

Title: Manager, Electric Rate
Dan Pease

Date: 3/16/07

PACIFIC GAS AND ELECTRIC COMPANY
PHASE 2 OF THE 2007 GENERAL RATE CASE
STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBITS

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBIT A
Energy and Non-Energy Rates for Schedules LS-1, LS-2, LS-3 and OL-1

EXHIBIT A, Page 1

Non-Energy Charges for Schedules LS-1, LS-2 and OL-1

	Rate Schedule	Service	Plant Charge Per Month	Universal Charge	O&M Charge	Total Monthly Facility Charge
1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights	$3.777	$0.187	$2.501	$6.465
2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities	$2.268	$0.187	$2.501	$4.956
3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required (ownership of pole or post, support arm and foundation by customer).	$2.260	$0.187	$2.501	$4.948
4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation	$5.388	$0.187	$2.501	$8.076
5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation.	$4.914	$0.187	$2.501	$7.603
6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its wood pole or post, installed solely for the luminaire.	$4.989	$0.187	$2.501	$7.678
7	LS-2A	City Owned and Maintained	$0.000	$0.187		$0.187
8	LS-2B & 2C	City Owned and PG&E Maintained	$0.000	$0.187	$2.501	$2.688
9	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property.	$3.777	$0.187	$2.501	$6.465
10	SP-2A1			$0.187		$0.187

EXHIBIT A, Page 2					
Energy Charges for Schedules LS-1, LS-2, LS-3 and OL-1 ($/kilowatt-hour)					
	Distribution	Generation	Public Purpose Programs	Other	Total
LS-1, LS-2, LS-3	$0.02502	$0.06658	$0.00610	$0.01297	$0.11067
OL-1	$0.02502	$0.06658	$0.01097	$0.01297	$0.11554

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBIT B
City and County of San Francisco Streetlight Rates

Streetlight Rate Design Settlement
EXHIBIT B, Page 1
City and County of San Francisco

Rate Schedule	Typical Lamp Type & Size	Full Cost	Present Rates	CCSF Proposed Rates Year 1	Phase In*	Year 2	Phase In*
CCSF Rate Schedule No. 1 LS-1A	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	$6.519	$5.006	$5.384	1/4	$5.763	2/4
CCSF Rate Schedule No. 3 LS-1A	HIGH PRESSURE SODIUM VAPOR 150 WATTS 16,000 LUMENS	$6.525	$5.053	$5.421	1/4	$5.789	2/4
CCSF Rate Schedule No. 4E LS-1E	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	$7.684	$7.980	$7.684	1/4	$7.684	2/4
CCSF Rate Schedule No. 4A LS-1E	MERCURY VAPOR 175 WATTS 7,500 LUMENS	$9.002	$6.890	$7.418	1/4	$7.946	2/4
CCSF Rate Schedule No. 6 LS-2B	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	$2.688	$2.095	$2.243	1/4	$2.392	2/4
Nonstandard - No PG&E Equivalent CCSF Rate Schedule No. 4A	Incandescent: 295 WATTS 4,000 LUMENS	$8.500	$5.049	$5.739	1/5	$6.429	2/5
	Mercury Vapor: 400 WATTS 21,000 LUMENS	$8.804	$7.942	$8.114	1/5	$8.287	2/5
CCSF Rate Schedule No. 5	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	$8.932	$4.906	$5.711	1/5	$6.516	2/5
	Incandescent: 405 WATTS 6,000 LUMENS	$10.171	$6.271	$7.051	1/5	$7.831	2/5
CCSF Rate Schedule No. 6 (Chinatown Area)	High Pressure Sodium Vapor 250 WATTS 28,000 LUMENS	$74.094	$16.158	$27.745	1/5	$39.332	2/5
CCSF Rate Schedule No. 7		Based on Time & Material.					
CCSF Rate Schedule No. 9 (Triangle District)	High Pressure Sodium Vapor 150W 16,000 LUMENS DUPLEX (1)	$29.029	$7.720	$11.982	1/5	$16.244	2/5
	150W 16,000 LUMENS DUPLEX (2)	$3.750	$2.850	$3.030	1/5	$3.210	2/5

Notes: The rate(s) for each City and County of San Francisco rate schedule is based on a typical lamp within each rate schedule.

Phase-in: Numerator of fraction identifies number of years the phase-in has occurred.
Denominator of fraction identifies span of years for the phase-in period.

Streetlight Rate Design Settlement
EXHIBIT B, Page 2
City and County of San Francisco

		CCSF Proposed Rates					
Rate Schedule	**Typical Lamp Type & Size**	**Year 3**	**Phase In***	**Year 4**	**Phase In***	**Year 5**	**Phase In***
CCSF Rate Schedule No. 1							
LS-1A	HIGH PRESSURE SODIUM VAPOR						
	100 WATTS 9,500 LUMENS	$6.141	3/4	$6.519	4/4		
CCSF Rate Schedule No. 3							
LS-1A	HIGH PRESSURE SODIUM VAPOR						
	150 WATTS 16,000 LUMENS	$6.157	3/4	$6.525	4/4		
CCSF Rate Schedule No. 4E							
LS-1E	HIGH PRESSURE SODIUM VAPOR						
	100 WATTS 9,500 LUMENS	$7.684	3/4	$7.684	4/4		
CCSF Rate Schedule No. 4A							
LS-1E	MERCURY VAPOR						
	175 WATTS 7,500 LUMENS	$8.474	3/4	$9.002	4/4		
CCSF Rate Schedule No. 6							
LS-2B	High Pressure Sodium Vapor						
	100 WATTS 9,500 LUMENS	$2.540	3/4	$2.688	4/4		
Nonstandard - No PG&E Equivalent							
CCSF Rate Schedule No. 4A							
	Incandescent:						
	295 WATTS 4,000 LUMENS	$7.119	3/5	$7.809	4/5	$8.500	5/5
	Mercury Vapor:						
	400 WATTS 21,000 LUMENS	$8.459	3/5	$8.632	4/5	$8.804	5/5
CCSF Rate Schedule No. 5							
	High Pressure Sodium Vapor						
	100 WATTS 9,500 LUMENS	$7.321	3/5	$8.127	4/5	$8.932	5/5
	Incandescent:						
	405 WATTS 6,000 LUMENS	$8.611	3/5	$9.391	4/5	$10.171	5/5
CCSF Rate Schedule No. 6							
(Chinatown Area)	High Pressure Sodium Vapor						
	250 WATTS 28,000 LUMENS	$50.920	3/5	$62.507	4/5	$74.094	5/5
CCSF Rate Schedule No. 7							
CCSF Rate Schedule No. 9							
(Triangle District)	High Pressure Sodium Vapor						
	150W 16,000 LUMENS DUPLEX (1)	$20.505	3/5	$24.767	4/5	$29.029	5/5
	150W 16,000 LUMENS DUPLEX (2)	$3.390	3/5	$3.570	4/5	$3.750	5/5

Notes: The rate(s) for each City and County of San Francisco rate schedule is based on a typical lamp within each rate schedule.

Phase-in: Numerator of fraction identifies number of years the phase-in has occurred.
Denominator of fraction identifies span of years for the phase-in period.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT C

Electric Rate Schedule LS-1

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING

APPLICABILITY: This schedule is applicable to PG&E-owned and maintained lighting installations which illuminate streets, highways, and other outdoor ways and places and which generally (T) utilize PG&E's distribution facilities under the provisions contained below. Rates of Class (T) A through Class F service will be applicable as determined in Special Condition 4.

TERRITORY: The entire territory served.

RATES: Rates are separated into two parts: facility and energy. (N)

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size. Monthly energy charges are based on the kWh usage of each lamp.

Monthly energy charges per lamp are calculated using the following formula: (Lamp wattage + ballast wattage) x 4,100 hours/12 months/1000 x streetlight energy rate per kilowatt hour (kWh). Ballast wattage = ballast factor x lamp wattage.

Total bundled monthly energy charges for the most common lamps billed by PG&E on the approval date of this tariff are shown below. Subsequent additional lamps billed within the wattage ranges listed in the ballast factor table will be calculated using the same formula shown above.

The various ballast wattages used in the monthly energy charge calculations can be found in the Ballast Factor table following the monthly energy charges. Ballast factors are averaged within each grouping (range of wattages). The same ballast factor is applied to all of the lamps that fall within its watt range. Applicant or Customer must provide third party documentation where manufacturer's information is not available for rated wattage consumption before PG&E will accept lamps for this schedule.

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be (N) calculated in accordance with Condition 17 'Billing' below.

(D)

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

(D)

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

			Facilities Charge Per Lamp Per Month					
CLASS		A	B	C**	D	E	F	(N)
		$6.465	$4.956	$4.948	$8.076	$7.603	$7.678	(N)

Energy Charge Per Lamp Per Month
All Night Rates

Nominal Lamp Rating

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes		Half-Hour Adjustment	
INCANDESCENT LAMPS*:						
58	20	600	TBD	(N)	TBD	(R)
92	31	1,000	TBD	|	TBD	|
189	65	2,500	TBD	|	TBD	|
295	101	4,000	TBD	|	TBD	|
405	139	6,000	TBD	|	TBD	|
MERCURY VAPOR LAMPS*:				|		|
100	40	3,500	TBD	|	TBD	|
175	68	7,500	TBD	|	TBD	|
250	97	11,000	TBD	|	TBD	|
400	152	21,000	TBD	|	TBD	|
700	266	37,000	TBD	|	TBD	|
HIGH PRESSURE SODIUM VAPOR LAMPS:				|		|
120 Volts				|		|
70	29	5,800	TBD	|	TBD	|
100	41	9,500	TBD	|	TBD	|
150	60	16,000	TBD	|	TBD	|
240 Volts				|		|
70	34	5,800	TBD	|	TBD	|
200	81	22,000	TBD	|	TBD	|
250	100	25,500	TBD	|	TBD	|
400	154	46,000	TBD	(N)	TBD	(R)

* Closed to new installations as of June 8, 1978, except where PG&E and customer shall agree, mercury vapor lamps may be installed under Class A and C to provide compatibility with existing light sources.

** Closed to new installation. See Special Condition 4.

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

Ballast Factors by Lamp Type and Watt Range (N)

Watt Range			Ballast Factor	(N)	Watt Range			Ballast Factor	(N)
MERCURY VAPOR					HIGH PRESSURE SODIUM VAPOR				
1	to	75	31.00%	(N)					
76	to	125	17.07%	|	120 Volts				
126	to	325	13.69%	|	1	to	40	25.44%	(N)
326	to	800	11.22%	|	41	to	60	22.93%	|
801	+		10.34%	|	61	to	85	21.25%	|
				|	86	to	125	20.00%	|
LOW PRESSURE SODIUM VAPOR				|	126	+		17.07%	|
1	to	40	75.61%	|					|
41	to	75	54.32%	|	240 Volts				|
76	to	110	46.34%	|	1	to	60	40.49%	|
111	to	160	34.42%	|	61	to	85	42.16%	|
161	+		26.83%	|	86	to	125	37.56%	|
				|	126	to	175	34.63%	|
METAL HALIDE				|	176	to	225	18.54%	|
0	to	85	25.44%	|	226	to	280	17.07%	|
86	to	200	20.39%	|	281	to	380	12.35%	|
201	to	375	22.93%	|	381	+		12.68%	|
376	to	700	18.54%	|					|
701	+		13.27%	(N)					(N)

* Closed to new installations as of June 8, 1978, except where PG&E and Customer shall agree, mercury vapor lamps may be installed under Class A and C to provide compatibility with existing light sources.

**Closed to new installations.

(Continued)

SCHEDULE LS-1–PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	TBD	(T)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components ($ per kWh)		
Generation	TBD	(T)
Distribution	TBD	|
Transmission*	TBD	|
Transmission Rate Adjustments* (all usage)	TBD	|
Reliability Services*	TBD	|
Public Purpose Programs	TBD	|
Nuclear Decommissioning	TBD	|
Competition Transition Charge	TBD	|
Energy Cost Recovery Amount	TBD	|
DWR Bond	TBD	(T)

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* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

MORE THAN ONE LIGHT ON A POLE: Where more than one light is installed on a pole, all lights other than the first will be billed on the Class C rate. Not applicable to installations made prior to September 11, 1978.

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE:** (a) PG&E provides basic lighting services with limited standard facilities, pole types and configurations. Applicants may view standard offerings at PG&E local offices or online at PGE.com; (b) Applicant or Customer is responsible for lighting pattern layout and coverage for safety considerations; and (c) PG&E reserves the right to supply either “multiple” or “series” service. Series service to new lights will only be made where it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **ANNUAL OPERATING SCHEDULE:** The above rates for All-Night (AN) service assume an average of approximately 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule agreeable to the Customer but not exceeding 4,100 hours per year. This is also predicated on an electronic type photo control meeting ANSI standard C.136.10, with a turn on value of 1.0 footcandles and turn off value of 1.5 foot candles. Electro mechanical or thermal type photo controls are not acceptable for this rate schedule.

3. **OPERATING SCHEDULES OTHER THAN ALL-NIGHT:** Rates for regular operating schedules other than full AN will be the AN rate plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of approximately 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or three hours per night, and may be applied for 24-hour operation. (N)

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

4. **DESCRIPTION OF SERVICE PROVIDED**

The following describes lighting facilities only. Lighting facilities payments, and service connections and payments, are described in Special Conditions 7, 8 and 9.

Class A: PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights formerly served under Schedule LS-1, Class A, as of September 11, 1978. There is no installation charge for this class.

Class B: PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where Customer has paid the estimated installed cost of the luminaire, support arm and control facilities (applicable only to installations in service as of September 11, 1978).

Class C: Closed to new mixed ownership installations as of March 1, 2006. Only used for multiple lights on PG&E-owned poles to avoid duplicate billing of poles.

Class D: PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard post (20-foot mounting height or less) and foundation, underground or overhead circuit.

Class E: PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, standard pole and foundation, underground or overhead circuit.

Class F: PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its standard pole or post, installed solely for the luminaire.

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

5. **REARRANGEMENT OF FACILITIES:** For any relocation, or rearrangement of PG&E's existing streetlight or service facilities at the request of the Customer and agreed to by PG&E, Customer shall pay PG&E, in advance, PG&E's estimated total cost of the relocation or rearrangement.

6. **SERVICE REQUESTS:** Service requests shall include form 72-1007 or 72-1008 for installation, removals, energizing and de-energizing of streetlight facilities.

7. **SERVICE AND LIGHTING INSTALLATION RESPONSIBILITIES:** The Applicant at its expense shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit, and substructures, including substructures for transformer installations if necessary, for street light service and circuits, in accordance with PG&E's specifications. Upon acceptance by PG&E, ownership of the conduit and substructures will automatically transfer to PG&E. Riser material is installed by PG&E at the Customer's expense. Tree trimming is the responsibility of the Applicant.

   PG&E will furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service from the distribution line source subject to the payment provision of Special condition 8.

   PG&E will establish service delivery points in close proximity to its distribution system as follows:

   OVERHEAD: (a) In an overhead area—a single drop will be installed; and (b) for an overhead to underground system, service will be established in a PG&E box at the base of the pole, or directly to a single light or to the first light of a multiple circuit based on PG&E's standard design, in the shortest most practical configuration from the connection on the distribution line source.

   UNDERGROUND: For an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service, transformer and secondary splice box, as required, will be installed in the shortest most practical configuration from the connection on the distribution line source.

   The Customer shall provide rights of way, clear route and access acceptable to PG&E in accordance with the provisions of electric Rule 16, and Special Condition 11 below.

   Line or service extensions not conforming to the foregoing descriptions shall be installed under Special Condition 13.

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

8. **NON REFUNDABLE PAYMENT FOR SERVICE POINT INSTALLATION**

a) The Applicant shall pay in advance the estimated installed cost of facilities necessary to establish a service delivery point to serve the street light or street light circuit, minus a one-time revenue allowance based on the kWh of energy usage and the distribution component of the energy rate posted in the rate schedule for the lamps installed. The total allowance shall be determined by taking the annual equivalent kWh multiplied by the distribution component, then divided by the cost of service factor used in electric Rule 15.C.

b) The allowance may only be provided where PG&E must install service facilities to connect street lights or street light circuits. No allowance will be provided where a simple connection is required, or in the case of a Class A installation. Only lights operating at a minimum on the full 11hour AN schedule shall be granted allowances. Where Applicant received allowances based upon 11 hour AN operation, no billing adjustments, as otherwise provided for in Special Condition 3, shall be made for the first three (3) years following commencement of service.

9. **PAYMENT FOR INSTALLATION OF LIGHTING FACILITIES:** PG&E will provide at its expense the luminaire kit and standard arm for LS-1A and LS-1C for second and multiple lights on a PG&E pole, for Class LS-1D, a standard post top, for Class LS-1E a luminiare kit, and for Class LS-1F a luminaire kit and standard arm. Customer or Applicant shall pay, in advance, the estimated installed cost of the remaining lighting facilities that PG&E is required to install. Allowances are not applied to street light facilities on the load side of the service delivery point.

Any attachments to street light poles requested by governmental agencies, requires prior approval by PG&E and execution of a license agreement. (N)
Unauthorized attachments are subject to removal. |
(N)

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

10. **OWNERSHIP:** All facilities installed under the provisions of this rate schedule shall be owned, operated and maintained by PG&E.

11. **MAINTENANCE, ACCESS, CLEARANCES**

    a) Maintenance: PG&E shall exercise reasonable care and diligence in maintaining PG&E-owned facilities.

    b) Access: Customer will maintain adequate access for PG&E's standard equipment used in maintaining facilities and for installation of its facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Applicant or Customer shall be responsible for rearrangement charges as provided for in Special Condition 5.

    c) Clearances: Customer will, at Customers expense, correct all access or clearance infractions, or pay PG&E's total estimated cost for PG&E to relocate facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service in accordance with electric Rule 11. Applicant or Customer shall be responsible for tree trimming to maintain lighting patterns of existing lights.

12. **SPECIAL EQUIPMENT:** Luminaires, poles, posts and other equipment requested by an Applicant or Customer in addition to or in substitution for PG&E's standard poles, posts, photo controls and equipment, will be provided if such equipment meets PG&E's engineering and operating standards, and if PG&E agrees to do so, provided that the Applicant or Customer pays the cost difference between the equipment normally installed by PG&E and the equipment requested by the Applicant or Customer, plus an additional Cost of Ownership payment as provided for in Section I.3 of electric Rule 2. This provision is also applicable to special optical filters, shields or other special hardware required or requested by the Applicant or Customer or any governmental agency having jurisdiction.

13. **LINE EXTENSIONS**

    A. Where PG&E extends its facilities to street light installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below. (N)

    B. Where PG&E extends its facilities to street light installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for these installations. (N)

(D)

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

14. **TEMPORARY DISCOUNTINUANCE OF SERVICE:** (Fixture remains in place.) At the request of the Customer, PG&E will temporarily discontinue service to the individual luminaires provided the Customer pays a facility charge equal to the all-night rate, adjusted to zero burning hours under the provisions of Special Condition 3, plus the estimated cost to disconnect and reconnect the light.

15. **CONTRACT:** Except as otherwise provided in this rate schedule, or where lighting service is installed in conjunction with facilities installed under the provisions of Rules 15 or 16, standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for installations, rearrangements or relocations.

16. **MINIMUM SERVICE PERIOD:** Temporary services will be installed under electric Rule 13.

17. **BILLING:** A Customer's bill is calculated based on the option applicable to the Customer. Payment will be made in accordance with PG&E's filed tariffs.

    Bundled Service Customers receive supply and delivery service solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

    Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

(Continued)

SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

17. **BILLING** (Cont'd.)

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	|
DWR Bond Charge (per kWh)	TBD	TBD	|
CTC Charge (per kWh)	TBD	TBD	|
Total CRS (per kWh)	TBD	TBD	(T)

18. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT D

Electric Rate Schedule LS-2

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

APPLICABILITY: This schedule is applicable service to lighting installations which illuminate streets, highways, and other publicly-dedicated outdoor ways and places where the Customer is a Governmental Agency and owns the lighting fixtures, poles and interconnecting circuits. The Customer's facilities must be of good construction acceptable to PG&E and in satisfactory condition to qualify for Class C rates. Class C is closed to new installations and additional lamps in existing accounts. (T) (T) (T)

TERRITORY: The entire territory served.

RATES: Rates are separated into two parts: facility and energy. (N)

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size. Monthly energy charges are based on the kWh usage of each lamp.

Monthly energy charges per lamp are calculated using the following formula: (Lamp wattage + ballast wattage) x 4,100 hours/12 months/1000 x streetlight energy rate per kilowatt hour (kWh). Ballast wattage = ballast factor x lamp wattage.

Total bundled monthly energy charges for the most common lamps billed by PG&E on the approval date of this tariff are shown below. Subsequent additional lamps billed within the wattage ranges listed in the ballast factor table will be calculated using the same formula shown above.

The various ballast wattages used in the monthly energy charge calculations can be found in the Ballast Factor table following the monthly energy charges. Ballast factors are averaged within each grouping (range of wattages). The same ballast factor is applied to all of the lamps that fall within its watt range. Applicant or Customer must provide third party documentation where manufacturer's information is not available for rated wattage consumption before PG&E will accept lamps for this schedule.
(N)

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with Condition 13 'Billing' below. (D)

(L)

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

	Facilities Charge Per Lamp Per Month					
CLASS	A	C**				
	$0.187	$2.688				(N)

Energy Charge Per Lamp Per Month
All Night Rates

CLASS: A — PG&E supplies energy and service only. (N) (N)

C — PG&E supplies the energy and maintenance service as described in Special Condition 8 (N) | (N)

Nominal Lamp Rating:

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS*	Per Lamp Per Month: All Classes				Half-Hour Adjustment	
INCANDESCENT LAMPS:								
58	20	600	TBD	(N)			TBD	(R)
92	31	1,000	TBD	|			TBD	|
189	65	2,500	TBD	|			TBD	|
295	101	4,000 **	TBD	|			TBD	|
405	139	6,000 **	TBD	|			TBD	|
620	212	10,000 **	TBD	|			TBD	|
860	294	15,000 **	TBD	|			TBD	|
MERCURY VAPOR LAMPS:				|				|
40	18	1,300	TBD	|			TBD	|
50	22	1,650	TBD	|			TBD	|
100	40	3,500	TBD	|			TBD	|
175	68	7,500	TBD	|			TBD	|
250	97	11,000	TBD	|			TBD	|
400	152	21,000	TBD	|			TBD	|
700	266	37,000	TBD	|			TBD	|
1,000	377	57,000	TBD	|			TBD	|
LIGHT EMITTING DIODE (LED) LAMPS: 120 VOLTS				|				|
42	14	837	TBD	(N)			TBD	(R)

* Latest published information should be consulted on best available lumens.
** Service for incandescent lamps over 2,500 lumens will be closed to new installations after September 11, 1978.
*** Closed to new installations and new lamps on existing circuits, see condition 8A.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

HIGH PRESSURE SODIUM VAPOR LAMPS AT:				(N)		(R)
120 VOLTS						
35	15	2,150	TBD		TBD	
50	21	3,800	TBD		TBD	
70	29	5,800	TBD		TBD	
100	41	9,500	TBD		TBD	
150	60	16,000	TBD		TBD	
200	80	22,000	TBD		TBD	
HIGH PRESSURE SODIUM VAPOR LAMPS AT:						
240 VOLTS						
50	24	3,800	TBD		TBD	
70	34	5,800	TBD		TBD	
100	47	9,500	TBD		TBD	
150	69	16,000	TBD		TBD	
200	81	22,000	TBD		TBD	
250	100	25,500	TBD		TBD	
310	119	37,000	TBD		TBD	
360	144	45,000	TBD		TBD	
400	154	46,000	TBD		TBD	
LOW PRESSURE SODIUM VAPOR LAMPS:						
35	21	4,800	TBD		TBD	
55	29	8,000	TBD		TBD	
90	45	13,500	TBD		TBD	
135	62	21,500	TBD		TBD	
180	78	33,000	TBD		TBD	
METAL HALIDE LAMPS:						
70	30	5,500	TBD		TBD	
100	41	8,500	TBD		TBD	
150	63	13,500	TBD		TBD	
175	72	14,000	TBD		TBD	
250	105	20,500	TBD		TBD	
400	162	30,000	TBD		TBD	
1,000	387	90,000	TBD		TBD	
INDUCTION LAMPS:						
55	19	3,000	TBD		TBD	
85	30	4,800	TBD		TBD	
165	58	12,000	TBD	(N)	TBD	(R)

Ballast Factors by Lamp Type and Wattage Range (N)

Watt Range			Ballast Factor	(N)	Watt Range			Ballast Factor	(N)
MERCURY VAPOR					HIGH PRESSURE SODIUM VAPOR				
1	to	75	31.00%	(N)					
76	to	125	17.07%		120 Volts				
126	to	325	13.69%			to	40	25.44%	(N)
326	to	800	11.22%		41	to	60	22.93%	
801	+		10.34%		61	to	85	21.25%	
					86	to	125	20.00%	
LOW PRESSURE SODIUM VAPOR					126	+		17.07%	
1	to	40	75.61%						
41	to	75	54.32%		120 Volts				

76	to	110	46.34%	|
111	to	160	34.42%	|
161	+		26.83%	|
				|
METAL HALIDE				|
0	to	85	25.44%	|
86	to	200	20.39%	|
201	to	375	22.93%	|
376	to	700	18.54%	|
701	+		13.27%	(N)

1	to	60	40.49%	|
61	to	85	42.16%	|
86	to	125	37.56%	|
126	to	175	34.63%	|
176	to	225	18.54%	|
226	to	280	17.07%	|
281	to	380	12.35%	|
381	+		12.68%	(N)

(Continued)

SCHEDULE LS-2–CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES:
(Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	TBD	(T)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components ($ per kWh)		
Generation	TBD	(T)
Distribution	TBD	|
Transmission*	TBD	|
Transmission Rate Adjustments*	TBD	|
Reliability Services*	TBD	|
Public Purpose Programs	TBD	|
Nuclear Decommissioning	TBD	|
Competition Transition Charge	TBD	|
Energy Cost Recovery Amount	TBD	|
DWR Bond	TBD	(T)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE:** This schedule is applicable to multiple lighting systems to which PG&E will deliver current at secondary voltage. Multiple current will normally be supplied at 120/240 Volt, single-phase. In certain localities PG&E may supply service from 120/208 Volt, wye-systems, polyphase lines in place of 240 Volt service. Unless otherwise agreed, existing series current will be delivered at 6.6 amperes. Single-phase service from 480 Volt sources and series circuits will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint. All currents and voltages stated herein are nominal, reasonable variations being permitted.

   New lights will normally be supplied as multiple systems. Series service to new lights will be made only when it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **SERVICE REQUIREMENTS**

   a) **PHOTO CONTROLS**

      This rate schedule is predicated on an electronic type photo controls meeting ANSI standard C136.10, with a turn on value of 1.0 foot-candles and a turn-off value of 1.5 foot-candles. Electro-mechanical or thermal type photo controls are not acceptable for this rate schedule.

   b) **LIGHT OR POLE NUMBERING**

      As agreed upon by the parties, pole number sequencing and coding for single lights or multiple lights on a single pole, shall be provided by either party and must conform to PG&E's billing system. Customer will provide physical numbering on lights or poles for LS-2 installations in order to facilitate accurate billing and inventory reporting. Numbering is required prior to energizing facilities. Numbering must be legible from the ground.

   c) **SERVICE REQUESTS**

      Service request shall include form 72-1007 for installation and energizing, and form 72-1008 for removing or de-energizing Customer's facilities.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

3. **SERVICE INSTALLATION**

PG&E will establish service delivery points within close proximity to its distribution system.

a) **Overhead:** In an overhead area, a single drop will be installed. For an overhead to underground system, service will be established in a PG&E box at the base of the riser pole or other agreed upon location within close proximity. PG&E will connect Customer's conductors at the service delivery point.

b) **Underground:** In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service, transformer and secondary splice box, as required, will be installed in the shortest most practical configuration from the connection on the distribution line source. Customer shall install and own all facilities from the service delivery point on PG&E's system.

c) **Customer Installation Responsibility:** Customer shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant, at its expense, shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit and substructures (including substructures for transformer installations, if necessary, for street lights only) in accordance with PG&E's specifications. Riser material shall be installed by PG&E at the Customer's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer shall provide rights of way as provided in electric Rule 16.

d) **PG&E Installation Responsibility:** PG&E shall furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service to the distribution line source, subject to the payment provisions of Special Condition 4. Only duly authorized employees of PG&E shall connect Customer's loads to, or disconnect the same from, PG&E's electrical distribution facilities.

e) **Rearrangements:** Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation, or rearrangement of PG&E's existing street light or service facilities requested by Customer or Applicant and agreed to by PG&E.

f) **Non-conforming Load:** Applicant or Customer must be a governmental agency. Any load, other then the lighting loads listed in the Rate table above, is non conforming load. Non conforming load may be connected to customer circuits not to exceed 150 watts per circuit, or light for individually connected lights. Loads will conform to the requirements of Agreement form 79-1048 available on PG&E's web site, http://www.pge.com/tariffs/EF.SHTML#EF for electric forms. All other non conforming load connected to unmetered LS-2 facilities exceeding this limitation, requires metering of the Customer's system at PG&E's service delivery point. (N)
(N)

(D)

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

4. **NON REFUNDABLE PAYMENT FOR SERVICE INSTALLATION**

a) Customer or Applicant shall pay in advance the estimated installed cost necessary to establish a service delivery point. A one-time revenue allowance will be provided based on Customer's kWh usage and the distribution component of the energy rate posted in the Rate Schedule for the lamps installed. The total allowance shall be determined by taking the annual equivalent kWh times the Distribution component of this rate divided by the cost of service factor shown in Electric Rule 15.C.

b) The allowance will only be provided where PG&E must install capital assets to connect load. No allowance will be provided where a simple connection is required. Only lights on a minimum 11 hour All Night (AN) schedule for permanent service shall be granted an allowance. Where Applicant received allowances based upon 11 hour AN operation, no billing adjustments, as otherwise provided for in Special Condition 7, shall be made for the first three (3) years following commencement of service.

Line or service extensions in excess of the above shall be installed under Special Condition 9.

5. **TEMPORARY SERVICE:** Temporary services will be installed under electric Rule 13.

6. **ANNUAL OPERATING SCHEDULES:** The above rates for AN service assume 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule selected by the Customer but not exceeding 4,100 hours per year.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

7. **OPERATING SCHEDULES OTHER THAN ALL-NIGHT:** Rates for regular operating schedules other than full all-night will be the AN rate, plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or 3 hours per night, and may be applied for 24 hour operation. Photo control devices used for more or less than AN must be approved by PG&E prior to adjustments in billing. (T)

8. **MAINTENANCE, ACCESS, CLEARANCES**

   a) Maintenance

      The Class B and C rates include all labor and material necessary for the inspection, cleaning, or replacement by PG&E of lamps and glassware. Replacement is limited to certain glassware such as is commonly used and manufactured in reasonably large quantities. A commensurate extra charge will be made for maintenance of glassware of a type entailing unusual expense. The Class C rate also includes all labor and material necessary for replacement by PG&E of photoelectric controls. Class B and C rates are closed to new installations and to additional lamps in existing accounts as of March 1, 2006.

   b) Under the grand fathered Class B and C rates, the following shall apply:

      1) At Customer's request, where PG&E's resources permit, PG&E will paint poles for Customer on a time and material basis. This service will only be offered for poles that have been designed to be painted.

      2) PG&E will Isolate any trouble in the Customer's system which has resulted in an outage or diminished light output.

      3) PG&E will make necessary repairs which do not require wiring replacement on accessible wiring between poles and on equipment and wiring in and on poles to keep the system in operating condition.

      4) PG&E will provide labor for the replacement of material such as ballasts, relays, fixtures, individual cable runs between poles where such runs are in conduit, and other individual parts of the system that are not capital items.

      5) Customer shall compensate PG&E for any material furnished by PG&E not included in 8.A. above. The exception for Class B is that photo control replacement is not included in the rate. Customer must have been on Class C for this service.

      6) PG&E shall not be responsible for excavation or any major replacement of circuits, conduits, poles, or fixtures owned by the Customer.

      7) Tree trimming is the responsibility of the Customer for installation of new lights or for maintaining lighting patterns of existing lights.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

8. **MAINTENANCE, ACCESS, CLEARANCES** (Cont'd.)

c) Access

Customer will maintain adequate access for PG&E's standard equipment used in maintaining facilities and for installation of its facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Applicant or Customer shall be responsible for rearrangement charges as provided for in Special Condition 3.e.

d) Clearances

Customer applicant shall, at its expense, correct all access or clearance infractions, or pay PG&E its total estimated cost for PG&E to relocate facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service in accordance with electric Rule 11. Applicant or Customer shall be responsible for tree trimming to maintain lighting patterns of existing lights.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

9. **LINE EXTENSIONS**

A. Where PG&E extends its facilities to street light installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below. (N)

B. Where PG&E extends its facilities to street light installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for these installations. (N)

(D)

10. **STREET LIGHT LAMPS – STANDARD AND NONSTANDARD RATINGS:** The rates under Classes B and C are applicable to both standard and group replacement street lamps. Standard and group replacement street lamps have reference only to street lamps having wattage and operating life ratings within three percent of those specified in the EEI-NEMA Standards for Filament Lamps Used in Street Lighting. Where Class A service is supplied to lamps of other ratings than those specified in EEI-NEMA Standards an adjustment will be made in the lamp rates proportionate to the difference between the wattage of the lamps and the standard lamps of the same lumen rating.

11. **CONTRACT:** Except as otherwise provided in this rate schedule, or where lighting service is installed in conjunction with facilities installed under the provisions of Rules 15 or 16, standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for installations, rearrangements or relocations.

12. **POLE CONTACT AGREEMENT:** Where Customer requests to have a portion or all Customer owned street lighting facilities in contact with PG&E's distribution poles, a Customer-Owned Streetlights PG&E Pole Contact Agreement (Form 79 938) will be required.

(Continued)

SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

13. **BILLING:** This Rate Schedule is subject to PG&E's other rules governing billing issues, as may be applicable. PG&E performs regular auditing as part of this rate schedule. (N)

(D)

Bundled Service Customers receive supply and delivery service solely from PG&E. The Customer's bill is based on the Total Rate set forth above.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	|
DWR Bond Charge (per kWh)	TBD	TBD	|
CTC Charge (per kWh)	TBD	TBD	|
Total CRS (per kWh)	TBD	TBD	(T)

14. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT E

Electric Rate Schedule LS-3

SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE

APPLICABILITY: Applicable to service to electrolier lighting systems, excluding incandescent luminairies, which illuminate streets, highways, and other outdoor ways and places where the Customer owns the lighting fixtures, poles and interconnecting circuits, and PG&E furnishes metered energy. Customers may connect incidental load on a single service account, not to exceed 5% of Customer's total circuit load on the account. Total lighting load must operate in conformance with the 85% off-peak design of this Rate. Architectural or landscape lighting for publicly dedicated outdoor ways and places is allowed under this schedule. All lighting must be power factor corrected in accordance with electric Rule 2G. Where loads are found outside these limits PG&E will default the rate to A1 General Service. (T) (N) (N)

TERRITORY: The entire territory served.

RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL RATES

Total Customer Charge ($ per meter per day)	$0.19713 (I)	
Total Energy Rate ($ per kWh)	TBD	(T)

UNBUNDLING OF TOTAL RATES

Total bundled service charges shown on Customers' bills are unbundled according to the component rates shown below.

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rate by Components ($ per kWh)		
Generation	TBD	(T)
Distribution	TBD	|
Transmission*	TBD	|
Transmission Rate Adjustments*	TBD	|
Reliability Services*	TBD	|
Public Purpose Programs	TBD	|
Nuclear Decommissioning	TBD	|
Competition Transition Charge	TBD	|
Energy Cost Recovery Amount	TBD	|
DWR Bond	TBD	(T)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE:** This schedule is applicable to multiple lighting systems to which PG&E will deliver current at a) secondary voltage and b) to series street lighting systems for which PG&E will furnish constant current regulating transformers. Service to series systems through PG&E-furnished constant current regulating transformers is closed to new installations. Multiple current will normally be supplied at 120/240 Volts, single-phase. (In certain localities PG&E supplies service from 120/208 Volt, wye-systems, polyphase lines in place of 240 Volt service.) Unless otherwise agreed, existing series current will be delivered at 6.6 amperes. Single-phase service from 480 volt sources will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint. All currents and voltages stated herein are nominal, reasonable variations being permitted.

   New lights will normally be supplied as multiple systems. Series service to new lights will be made only when it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **SERVICE CONNECTIONS**

   OVERHEAD: In an overhead area a single drop will be installed to the Customer owned pole where such pole meets permanent service pole requirements. For an overhead to underground system, service will be established from a riser to the Customer's appropriate termination facility described below.

   UNDERGROUND: In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service delivery point, transformer and secondary splice box, as required, will be installed in the shortest, most practical configuration from the connection on the distribution line source.

   GENERAL

   a) PG&E may, at its option, establish service to Customer's meter pedestal where (1) that pedestal meets all safety requirements under PG&E's design requirements for meter locations, and other tariff requirements of PG&E; (2) the pedestal is adjacent to readily available secondary facilities; and (3) no line extension is required. PG&E may at its option, agree to terminate in a Customer-owned box only when it is immediately adjacent to the pedestal.

   b) Where the Customer chooses to own the service wire and conduit from its termination point to the service delivery point on PG&E's secondary distribution system, PG&E will establish service delivery points in close proximity to its distribution system. No additional junction boxes may be placed between the service delivery point and the Customer's termination point.

(Continued)

SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

2. **SERVICE CONNECTIONS** (Cont'd.)

   GENERAL (Cont'd.)

   c) Line extensions shall be installed as provided in Special Condition 6.

   d) The Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation, or rearrangement of PG&E's existing street light or service facilities if requested by Customer or Applicant and agreed to by PG&E.

   e) **Customer Installation Responsibility:** Customer shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant, at its expense, shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit and substructures, (including substructures for transformer installations if necessary for street lights only) in accordance with PG&E's specifications. Riser material will be installed by PG&E at the Customer's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer will provide rights of way as provided in electric Rule 16. Customer will attach sufficient labeling to facilities to indicate metered lighting. (N) (N)

   f) **PG&E Installation Responsibility:** PG&E shall furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service to the distribution line source subject to the payment provisions of Special Condition 3. Only duly authorized employees of PG&E shall connect Customer's loads to, or disconnect the same from, PG&E's electrical distribution facilities.

   g) Temporary services will be installed under the provisions of electric Rule 13.

3. **NON REFUNDABLE PAYMENT FOR SERVICE POINT INSTALLATION**

   The Applicant shall pay in advance the estimated installed cost minus a one-time average revenue allowance. Annually, PG&E will determine a fixed average allowance by taking the average annual equivalent kWh for the class multiplied by the distribution component of the energy rate, then divided by the cost of service factor shown in electric Rule 15.C (N) | | (N)

   (D)

4. **METERING:** Each point of delivery to an electrolier circuit or circuits will be metered and billed separately.

(Continued)

SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

5. **MAINTENANCE, ACCESS, CLEARANCES:** This schedule does not contemplate maintenance within the rates as shown above.

   a. Customer or Applicant shall maintain adequate access for PG&E's standard equipment used in installing and maintaining facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Re-arrangement charges are outlined in Special Condition 2.d.

   b. Customer or Applicant shall, at its expense, correct all access or clearance infractions or pay PG&E's total estimated cost to relocate PG&E's facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service as provided in electric Rule 11.

6. **LINE EXTENSIONS**

   A. Where PG&E extends its facilities to street light installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below. (N)

   B. Where PG&E extends its facilities to street light installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for these installations. (N)

(D)

(Continued)

SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

7. **BILLING:** A customer's bill is calculated based on the option applicable to the customer.

Bundled Service Customers receive supply and delivery service solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	|
DWR Bond Charge (per kWh)	TBD	TBD	|
CTC Charge (per kWh)	TBD	TBD	|
			|
Total CRS (per kWh)	TBD	TBD	(T)

8. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT F

Electric Rate Schedule TC-1

SCHEDULE TC-1—TRAFFIC CONTROL SERVICE

APPLICABILITY: Applicable to metered service for traffic control related equipment operating on a 24-hour basis, owned by governmental agencies and located on streets, highways and other publicly-dedicated outdoor ways and places. Streetlights on traffic circuits and other equipment operating on a 24-hour basis in conformity with this rate design, may also be connected under this Schedule. Also applicable for service to these installations where service is initially established in the name of a developer who has installed such systems as required by a governmental agency, where ownership of facilities and responsibility for service will ultimately be transferred to the jurisdiction requiring the installation. Non-conforming incidental load such as low voltage sprinkler controls may also be attached where such loads do not exceed 5% of the total connected load served under a TC-1 Service Account. Maximum load per meter is 34,000 kWh per month. (T) (D) (N) (N) (N) (N)

TERRITORY: The entire territory served.

RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL RATES

Customer Charge Rate ($ per meter per day)	TBD	(T)
Energy Rate ($ per kWh)	TBD	(T)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rate by Components ($ per kWh)		
Generation	TBD	(T)
Distribution	TBD	|
Transmission*	TBD	|
Transmission Rate Adjustments*	TBD	|
Reliability Services*	TBD	|
Public Purpose Programs	TBD	|
Nuclear Decommissioning	TBD	|
Competition Transition Charge	TBD	|
Energy Cost Recovery Amount	TBD	(T)
DWR Bond		

____

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

SCHEDULE TC-1—TRAFFIC CONTROL SERVICE
(Continued)

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE:** Energy will normally be supplied at 120/240 Volt single-phase service (120/208 volts wye-systems in certain localities). Single-phase service from 480 Volt sources will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint.

2. **SERVICE CONNECTIONS**

OVERHEAD: In an overhead area a single drop will be installed to the Customer - owned pole where such pole meets permanent service pole requirements. For an overhead to underground system service will be established from a riser to the Customer's appropriate termination facility as described below.

UNDERGROUND: In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service delivery point, transformer and secondary splice box, as required, will be installed in the shortest, most practical configuration from the connection on the distribution line source.

GENERAL

a) PG&E may, at its option, establish service to Customer's meter pedestal where 1) that pedestal meets all safety requirements under PG&E's design requirements for meter locations, and other tariff requirements of PG&E; 2) the pedestal is adjacent to readily available secondary facilities; and 3) no line extension is required. PG&E may at its option, agree to terminate in a Customer owned box only when it is immediately adjacent to the pedestal.

b) Where the Customer chooses to own the service wire and conduit from its termination point to the service delivery point on PG&E's secondary distribution system, PG&E will establish service delivery points in close proximity to its distribution system. No additional junction boxes may be placed between the service delivery point and the Customer's termination point.

c) Line extensions shall be installed as provided in special condition 6.

d) Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation, or rearrangement of PG&E's existing street light or service facilities if requested by Customer or Applicant and agreed to by PG&E.

e) **Customer Installation Responsibility:** Customer or Applicant shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant shall, at its expense, perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit, substructures (including substructures for transformer installations if necessary) in accordance with PG&E's specifications. Riser material will be installed by PG&E at the Customer's or Applicant's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer or Applicant shall provide rights of way consistent with the provisions of electric Rule 16.

(Continued)

SCHEDULE TC-1—TRAFFIC CONTROL SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

2. **SERVICE CONNECTIONS** (Cont'd.)

GENERAL (Cont'd.)

f) **PG&E Installation Responsibility:** PG&E shall furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service to the distribution line source subject to the payment provisions of special condition 3. Only duly authorized employees of PG&E shall connect Customer's loads to, or disconnect the same from, PG&E's electrical distribution facilities.

g) Temporary services will be installed under the provisions of electric Rule 13.

3. **NON REFUNDABLE PAYMENT FOR SERVICE POINT INSTALLATION**

Customer or Applicant shall pay in advance the estimated installed cost minus a one-time average revenue allowance. Annually, PG&E will determine a fixed average allowance by taking the average annual equivalent kWh for the class multiplied by the distribution component of the energy rate, then divided by the cost of service factor shown in electric Rule 15.C. (N) (N)

(D)

4. **METERING:** Each point of delivery will be metered and billed separately.

5. **MAINTENANCE:** Maintenance will be performed by the Customer.

6. **LINE EXTENSION**

A. Where PG&E extends its facilities to Traffic Control installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below. (N)

B. Where PG&E extends its facilities to Traffic Control installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for these installations. (N) (D)

7. **MAINTENANCE, ACCESS, CLEARANCES**

a) Customer or Applicant will maintain adequate access for PG&E's standard equipment used in installing and maintaining facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Rearrangement charges are outlined in special condition 2.d.

b) Customer or Applicant shall, at its expense, correct all access or clearance infractions or pay PG&E's total estimated cost to relocate PG&E's facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service as provided in electric Rule 11.

(Continued)

SCHEDULE TC-1—TRAFFIC CONTROL SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

8. **BILLING:** A Customer's bill is calculated based on the option applicable to the Customer. Payment will be made in accordance with PG&E's filed tariffs.

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	|
DWR Bond Charge (per kWh)	TBD	TBD	|
CTC Charge (per kWh)	TBD	TBD	|
Total CRS (per kWh)	TBD	TBD	(T)

9. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

(END OF APPENDIX D)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Medium and Large Light and Power (MLLP) Rate Design Settlement Agreement (Settling Parties, MLLP Settlement) agree on a mutually acceptable outcome to the MLLP rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This MLLP Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses MLLP issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this MLLP Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this MLLP Settlement are set forth herein.

II. MLLP SETTLING PARTIES

The MLLP Settling Parties are as follows:

- Building Owners and Managers Associations of San Francisco and of California (BOMA)
- California Large Energy Consumers Association (CLECA)
- California League of Food Processors (CLFP)
- California Manufacturers & Technology Association (CMTA)
- California Retailers Association (CRA)
- Cogeneration Association of California (CAC)

- Direct Access Customer Coalition (DACC)
- Energy Producers and Users Coalition (EPUC)
- Energy Users Forum (EUF)
- Federal Executive Agencies (FEA)
- Indicated Commercial Parties (ICP)
- Pacific Gas and Electric Company (PG&E)

III. MLLP SETTLEMENT CONDITIONS

This MLLP Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on MLLP rate design, subject to the conditions set forth below:

1. This MLLP Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This MLLP Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.

2. This MLLP Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This MLLP Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

3. The Settling Parties agree that this MLLP Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

4. The Settling Parties agree that no provision of this MLLP Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.

5. This MLLP Settlement may be amended or changed only by a written agreement

signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this MLLP Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the MLLP Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the MLLP rate design agreed to herein. In the event the Commission rejects or modifies this MLLP Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, on March 5, 2007 parties to this MLLP Settlement reached a final agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. MLLP SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of rate design for the MLLP classes is to take the revenue allocations reached for those classes in the February 9 Settlement and ensure that they are fully recovered through MLLP rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the February 9 Settlement, and reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which was based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this MLLP Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the MLLP classes and will differ from the rates presented herein. However, these actual rates shall be based on the rate design methods described below.

Illustrative rates for Schedules A-10, A-10 TOU, E-19, E-20, and Standby are set forth in Exhibit A to this MLLP Settlement. The terms of this Settlement Agreement for Standby Service are reflected in draft tariffs, as appropriate, and pro forma standby tariff changes are attached to this MLLP Settlement as Exhibit B.

The Settling Parties agree that all testimony served prior to the date of this MLLP Settlement that addresses the issues resolved by this MLLP Settlement should be admitted into evidence without cross-examination by the Settling Parties. The Settling

Parties further agree that this MLLP Settlement resolves all MLLP rate design issues in A.06-03-005.

VI. MLLP RATE DESIGN SETTLEMENT TERMS

The Settling Parties agree that rates to collect the revenue allocated to the MLLP customer classes under the February 9 Settlement shall be designed as set forth below, including the voltage-level intra-class allocations for Schedule A-10 and standby service Schedule S as reflected in Exhibit A (which were not fully specified in the February 9 Settlement), and that these rates shall serve as a starting point for determining the changes to rates necessary to collect the adopted revenue requirement in effect when this Settlement is implemented.

1. Illustrative Settlement Rates

Illustrative settlement rates for the MLLP rate schedules are presented in Exhibit A. The rates were developed to collect the revenue allocated to the MLLP customer classes set forth in Tables 5-A and 5-B of the February 9 Settlement based on estimated March 2007 revenue requirements. Adopted revenue requirements in effect upon settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates will vary from those shown in Exhibit A when the Phase 2 rate changes are implemented.

2. Methods Used To Develop Illustrative Settlement Rates

The Settling Parties agree that the basic rate designs for each of the applicable MLLP rate schedules will be updated upon settlement implementation using the methods underlying development of the illustrative settlement rates for Schedules A-10, A-10 TOU, E-19, E-20, and Standby presented in Exhibit A. These methods reflect approaches proposed by PG&E in its Rate Update testimony, Exhibit (PG&E-4), filed June 26, 2006, as updated to incorporate the revenue allocation proposals and updated costs agreed upon in the February 9 Settlement. The Settling Parties have agreed to one additional modification of PG&E's MLLP proposals which is intended to ensure that total bundled service volumetric rates by TOU period under Schedules E-19 and E-20 will vary at least in proportion to the variation in PG&E's marginal energy costs. For service at transmission and primary distribution service voltages, this will involve setting Schedule E-19 and E-20 TOU generation energy charges residually, in such a way that the combined sum of generation energy charges and those non-bypassable charges that do not vary by TOU period vary in direct proportion to the TOU profile established by the settlement generation energy marginal costs. (This change affects bundled service rates under Schedules E-19 and E-20 but not Direct Access rates, because Direct Access customers do not pay generation energy charges.) This modification is not needed for the rates applicable to service at secondary distribution voltages under Schedules E-19 and E-20, because the volumetric rates for secondary voltage service include significant shares of both generation and distribution marginal capacity cost revenue in addition to marginal energy cost revenue, so these rates already vary in significantly greater proportion than do the underlying marginal generation energy costs. Distribution component demand and energy charge principles are based upon PG&E's filed proposals, as updated to reflect marginal costs from the February 9 Settlement. Where applicable (affecting a small number of Schedule A-10 and E-19V customers with historic demand levels of less than 20 kW), any FTA or RRBMA adjustments would then apply additively to establish total energy charges. The specific principle and methodology used to reshape the sum of generation energy charges and non-bypassable charges (for transmission and primary distribution service voltage volumetric rates by TOU period under Schedules E-19 and E-20) is to be utilized only upon initial settlement implementation, with subsequent component rate design changes between General Rate Cases governed by Term VII.3.(G) of the February 9 Settlement.

3. Adopt Revised Customer Charges

The Settling Parties agree that PG&E's proposed customer charges for the MLLP rate schedules are reasonable. The Settling Parties agree further that it is reasonable for the ongoing monthly TOU meter charges currently applicable for customers taking voluntary TOU service under Schedules E-19V and A-10 TOU to no longer be applied, at such time as the customer's existing TOU meter is replaced as part of the Advanced Meter Infrastructure (AMI) Project, pursuant to D. 06-07-027, and the new meter is activated and used for billing.

4. Rate Limiters for Schedules E-19 and E-20

The Settling Parties agree that it is reasonable to slightly reduce the protection provided by summer season average rate limiters for Schedules E-19 and E-20. Summer season average rate limiters will continue to be applicable for Schedule E-19 and E-20 customers taking service at secondary and primary distribution voltages, at the revised levels set forth in Exhibit A. The summer season average rate limiter will be based on a 26 percent load factor, rather than 32 percent as in current rates, for the duration of the 2007 GRC Phase 2 cycle, and will be considered for being eliminated entirely in PG&E's next GRC Phase 2 proceeding. The revised summer season average rate limiters would apply as caps on total amounts billed for bundled service usage, exclusive of customer charges, and thus provide summer-season bill protection comparable to but slightly less than those provided by the current average rate limiters. The Settling Parties understand that, consistent with past practice, the final rates upon implementation should incorporate adjustments to account for estimated undercollections associated with the average rate limiter.

5. Adopt Updated Standby Service Rates

The Settling Parties agree that PG&E's proposed methods for setting standby service rates as modified to reflect provisions of the February 9 Settlement and by the terms of this agreement produce rates that are just and reasonable, are in the public interest, and reflect a rational compromise of Settling Parties' original proposals. The Settling Parties understand that any rate changes adopted by the Federal Energy Regulatory Commission (FERC) for those rate elements over which FERC has jurisdiction will be passed through according to FERC rules. The Settling Parties also agree to modify certain terms and conditions of standby service, primarily as they relate to how standby contract demand levels are established, how reactive demand charges are administered and billed under Schedule S, and the applicable reactive demand charge rate, all as set forth in the pro forma tariff language in Exhibit B.

6. Provisions Related to Standard Non-Firm Service Rates

All parties to the February 9, 2007 Settlement have already agreed in Term VII.1.(G) that all non-firm customers will transfer to Base Interruptible Program Schedule E-BIP on or before January 1, 2008, and that the demand and energy charge incentives for service under the standard non-firm rate program should be converted to Schedule

E-BIP incentives and retained at the same absolute level of demand charge credits as are currently in effect for Schedule E-BIP service under Schedules A-10, E-19 and E-20. Thus, the Schedule E-BIP discounts in 2008 and subsequent years will be equal to the 2007 Schedule E-BIP discounts for Option A adopted by D.06-11-049, p. 27. In D.05-04-053, the Commission established a goal of eventually moving non-firm customers to service under Schedule E-BIP, with the understanding that Schedule E-BIP incentives are meant to be comparable to those available under the original non-firm tariffs. The Settling Parties agree that this settlement meets that objective.

7. Non-Firm Service and Demand Bidding Program Enrollment

The Settling Parties agree that it is reasonable for the terms of service under the Base Interruptible Program (Schedule E-BIP) to be modified so as to provide for E-BIP customers to also be automatically enrolled under Schedule E-DBP, PG&E's Demand Bidding Program. (Existing tariff provisions already allow for voluntary enrollment of non-firm service customers under the DBP, and preclude "dual payment," meaning that customers do not receive additional DBP incentive payments for load reductions on days that the interruptible programs are called upon.) This change should promote additional participation in the DBP from a group of customers whose operations are already particularly well-situated for demand response load reductions. Moreover, because customer participation in each DBP event is always voluntary, this change will not impose any new costs or obligations on the affected customers.

8. Franchise Fee Surcharge

The Settling Parties agree that PG&E's proposal to revise the franchise fee surcharge calculation for direct access and community choice aggregation customers, as set forth in Exhibit (PG&E-3), pages 1-15 to 1-16, is reasonable and should be adopted.

9. Timing of Structural Rate and Tariff Changes

Certain elements of this Settlement Agreement will require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. These changes include modifications to how the standby service contract demand levels and reactive demand charge will be billed and administered; and the staged discontinuation of voluntary TOU meter charges for Schedule E-19V customers as new AMI meters are installed and used for billing. These structural and system changes will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The Settling Parties recognize that these changes could take several months to implement.

VII. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Term VII. 2, shall apply to this MLLP Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This MLLP Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the MLLP Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this MLLP Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Building Owners and Managers Associations of
San Francisco and of California

By: /s/
B.F. Roberts

Title: President, Economic Sciences Corp.

Date: 3/14/07

California Large Energy Consumers Association

By: /s/
William Booth

Title: Counsel

Date: 3/13/07

California League of Food Processors

By: /s/
Rob Neenan

Title: Director of Regulatory Affairs

Date: 3/13/07

California Manufacturers & Technology Association

By: /s/
Keith McCrea

Title: Attorney

Date: 3/16/07

California Retailers Association

By: /s/
James Squeri

Title: Counsel

Date: 3/16/07

Cogeneration Association of California and
Energy Producers and Users Coalition

By: /s/
Nora Sheriff

Title: Counsel

Date: 3/16/07

Direct Access Customer Coalition

By: /s/
Greg Klatt

Title: Counsel

Date: 3/16/07

Energy Users Forum

By: /s/
Ann H. Kim

Title: on behalf of Carolyn Kehrein

Date: 3/16/07

Federal Executive Agencies

By: /s/
Norman Furuta

Title: Associate Counsel

Date: 3/15/07

Indicated Commercial Parties

By: /s/
Randall Keen

Title: Partner

Date: 3/16/07

Pacific Gas and Electric Company

By: /s/
Dan Pease

Title: Manager, Electric Rates

Date: 3/16/07

EXHIBIT A

ILLUSTRATIVE MLLP SETTLEMENT RATES

SCHEDULES A-10, E-19, E-20 and STANDBY

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Secondary
BUNDLED

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	21,681,788	$10.65	$230,916,139	21,681,788	$9.14	$198,103,098	
Winter							
Maximum	19,737,044	$5.33	$105,180,168	19,737,044	$5.33	$105,168,331	
Revenue from Demand Charges			$336,096,307			$303,271,428	
Revenue from Demand as % of Total			19.03%			18.07%	
ENERGY CHARGES - Non-FTA ($/kWh)							
Summer							
Total	6,404,230,928	$0.12615	$807,876,282	6,404,230,928	$0.11921	$763,436,991	
Winter							
Total	5,788,643,679	$0.09556	$553,175,139	5,788,643,679	$0.09033	$522,880,210	
Revenue from Energy Charges			$1,361,051,420			$1,286,317,201	
Revenue from Energy as % of Total			77.06%			76.64%	
CUSTOMER CHARGE ($/meter/mo.)							
A-10	739,180	$93	$69,083,763	739,180	$120	$88,701,600	
Revenue from Customer Charges			$69,083,763			$88,701,600	
Revenue from Customer Chrg as % of Total			3.91%			5.29%	
			$1,766,231,490			$1,678,290,229	Total Rev
						-4.98%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Primary
BUNDLED

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	185,725	$10.02	$1,860,236	185,725	$8.58	$1,593,412	
Winter							
Maximum	177,271	$4.82	$854,156	177,271	$4.90	$868,267	
Revenue from Demand Charges			$2,714,392			$2,461,678	
Revenue from Demand as % of Total			17.72%			17.76%	
ENERGY CHARGES - Non-FTA ($/kWh)							
Summer							
Total	57,183,236	$0.12651	$7,234,233	57,183,236	$0.11324	$6,475,211	
Winter							
Total	54,266,670	$0.09512	$5,161,974	54,266,670	$0.08574	$4,653,066	
Revenue from Energy Charges			$12,396,208			$11,128,276	
Revenue from Energy as % of Total			80.92%			80.31%	
CUSTOMER CHARGE ($/meter/mo.)							
A-10	2,226	$93	$208,042	2,226	$120	$267,120	
Revenue from Customer Charges			$208,042			$267,120	
Revenue from Customer Chrg as % of Total			1.36%			1.93%	
			$15,318,641			$13,857,075	Total Rev
						-9.54%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Transmission
BUNDLED

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	7,514	$7.01	$52,639	7,514	$6.33	$47,564	
Winter							
Maximum	7,838	$2.97	$23,269	7,838	$3.17	$24,827	
Revenue from Demand Charges			$75,908			$72,392	
Revenue from Demand as % of Total			11.96%			13.44%	
ENERGY CHARGES - Non-FTA ($/kWh)							
Summer							
Total	2,630,358	$0.11902	$313,072	2,630,358	$0.09824	$258,397	
Winter							
Total	2,589,834	$0.09130	$236,442	2,589,834	$0.07558	$195,728	
Revenue from Energy Charges			$549,514			$454,124	
Revenue from Energy as % of Total			86.57%			84.33%	
CUSTOMER CHARGE ($/meter/mo.)							
A-10	100	$93	$9,346	100	$120	$12,000	
Revenue from Customer Charges			$9,346			$12,000	
Revenue from Customer Chrg as % of Total			1.47%			2.23%	
			$634,768			$538,516	Total Rev
						-15.16%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Secondary TOU	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	21,681,788	$10.65	$230,916,139	21,681,788	$9.14	$198,103,098	
Winter							
Maximum	19,737,044	$5.33	$105,180,168	19,737,044	$5.33	$105,168,331	
Revenue from Demand Charges			$336,096,307			$303,271,428	
Revenue from Demand as % of Total			19.05%			18.07%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	1,722,114,841	$0.14554	$250,636,154	1,722,114,841	$0.13869	$238,842,120	
Part-Peak	1,621,311,492	$0.13410	$217,418,831	1,621,311,492	$0.11951	$193,757,746	
Off-Peak	3,060,804,595	$0.11063	$338,620,780	3,060,804,595	$0.10809	$330,837,125	
Winter							
Part-Peak	2,845,621,400	$0.10413	$296,304,519	2,845,621,400	$0.09498	$270,266,546	
Off-Peak	2,943,022,279	$0.08708	$256,272,282	2,943,022,279	$0.08583	$252,613,664	
Revenue from Energy Charges			$1,359,252,566			$1,286,317,201	
Revenue from Energy as % of Total			77.04%			76.64%	
CUSTOMER CHARGE ($/meter/mo.)	739,180	$93	$69,083,763	739,180	$120	$88,701,600	
Revenue from Customer Charges			$69,083,763			$88,701,600	
Revenue from Customer Chrg as % of Total			3.92%			5.29%	
			$1,764,432,636			$1,678,290,229	Total Rev
						-4.88%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Primary TOU	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	185,725	$10.02	$1,860,236	185,725	$8.58	$1,593,412	
Winter							
Maximum	177,271	$4.82	$854,156	177,271	$4.90	$868,267	
Revenue from Demand Charges			$2,714,392			$2,461,678	
Revenue from Demand as % of Total			17.74%			17.76%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	15,376,725	$0.14532	$2,234,563	15,376,725	$0.13077	$2,010,821	
Part-Peak	14,476,654	$0.13501	$1,954,550	14,476,654	$0.11371	$1,646,133	
Off-Peak	27,329,856	$0.11103	$3,034,538	27,329,856	$0.10312	$2,818,256	
Winter							
Part-Peak	26,676,784	$0.10315	$2,751,598	26,676,784	$0.08940	$2,384,883	
Off-Peak	27,589,886	$0.08717	$2,404,985	27,589,886	$0.08221	$2,268,182	
Revenue from Energy Charges			$12,380,234			$11,128,276	
Revenue from Energy as % of Total			80.90%			80.31%	
CUSTOMER CHARGE ($/meter/mo.)	2,226	$93	$208,042	2,226	$120	$267,120	
Revenue from Customer Charges			$208,042			$267,120	
Revenue from Customer Chrg as % of Total			1.36%			1.93%	
			$15,302,667			$13,857,074	Total Rev
						-9.45%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Transmission TOU	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)							
Summer							
Maximum	7,514	$7.01	$52,639	7,514	$6.33	$47,564	
Winter							
Maximum	7,838	$2.97	$23,269	7,838	$3.17	$24,827	
Revenue from Demand Charges			$75,908			$72,392	
Revenue from Demand as % of Total			11.97%			13.44%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	707,310	$0.13870	$98,101	707,310	$0.11499	$81,333	
Part-Peak	665,908	$0.12790	$85,168	665,908	$0.09851	$65,596	
Off-Peak	1,257,140	$0.10285	$129,291	1,257,140	$0.08867	$111,468	
Winter							
Part-Peak	1,273,128	$0.09975	$126,995	1,273,128	$0.07903	$100,620	
Off-Peak	1,316,705	$0.08292	$109,184	1,316,705	$0.07223	$95,108	
Revenue from Energy Charges			$548,739			$454,124	
Revenue from Energy as % of Total			86.55%			84.33%	
CUSTOMER CHARGE ($/meter/mo.)	100	$93	$9,346	100	$120	$12,000	
Revenue from Customer Charges			$9,346			$12,000	
Revenue from Customer Chrg as % of Total			1.47%			2.23%	
			$633,992			$538,516	Total Rev
						-15.06%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Secondary
FIRM

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	10,421,435	$15.02	$156,529,949		10,421,435	$11.40	$118,754,723	
Part-Peak	10,507,792	$3.57	$37,512,816		10,507,792	$2.63	$27,627,134	
Maximum	11,147,912	$6.74	$75,136,930		11,147,912	$7.28	$81,193,412	
Winter								
Part-Peak	9,536,989	$1.85	$17,643,430		9,536,989	$1.04	$9,956,199	
Maximum	9,691,385	$6.74	$65,319,938		9,691,385	$7.28	$70,585,112	
Revenue from Demand Charges			$352,143,062				$308,116,581	
Revenue from Demand as % of Total			31.16%				29.95%	
ENERGY CHARGES - Non-FTA ($/kWh)								
Summer								
Peak	968,999,344	$0.14032	$135,970,907		968,999,344	$0.12945	$125,436,778	
Part-Peak	1,043,401,250	$0.10163	$106,041,859		1,043,401,250	$0.08863	$92,479,174	
Off-Peak	2,542,920,149	$0.07173	$182,406,074		2,542,920,149	$0.07200	$183,079,701	
Winter								
Part-Peak	1,803,608,970	$0.09308	$167,881,633		1,803,608,970	$0.07899	$142,458,945	
Off-Peak	2,283,346,496	$0.07526	$171,846,823		2,283,346,496	$0.06957	$158,862,723	
Revenue from Energy Charges			$764,147,296				$702,317,321	
Revenue from Energy as % of Total			67.61%				68.28%	
AVERAGE RATE LIMITER - Summer ($/kWh)		$0.20969				$0.20651		
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
E-19	15,906	$275	$4,374,237	$9.03	15,906	$413	$6,561,355	$13.55
Rate V	96,857	$99	$9,574,336	$3.25	96,857	$120	$11,622,866	$3.94
Revenue from Customer Charges			$13,948,573				$18,184,221	
Revenue from Customer Chrg as % of Total			1.23%				1.77%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$1,130,238,930	Total Rev			$1,028,618,123	Total Rev
deviation above or below standard power factor of 85%							-8.99%	Change
OPTIONAL METER DATA		$0.98563	$30.00			$0.98563	$30.00	
ACCESS CHARGE ($/meter/day)		per day	per month			per day	per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Primary
FIRM

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	940,267	$10.61	$9,976,238		940,267	$10.31	$9,692,463	
Part-Peak	972,700	$2.43	$2,363,660		972,700	$2.37	$2,306,102	
Maximum	1,037,472	$4.78	$4,959,116		1,037,472	$6.24	$6,478,994	
Winter								
Part-Peak	904,482	$0.76	$687,406		904,482	$0.78	$708,475	
Maximum	935,869	$4.78	$4,473,452		935,869	$6.24	$5,844,483	
Revenue from Demand Charges			$22,459,872				$25,030,517	
Revenue from Demand as % of Total			25.08%				28.54%	
ENERGY CHARGES - Non-FTA ($/kWh)								
Summer								
Peak	83,239,439	$0.13126	$10,926,088		83,239,439	$0.12963	$10,790,341	
Part-Peak	92,778,773	$0.09789	$9,082,202		92,778,773	$0.08727	$8,097,252	
Off-Peak	235,041,650	$0.06977	$16,399,079		235,041,650	$0.06906	$16,230,934	
Winter								
Part-Peak	160,462,031	$0.08833	$14,173,763		160,462,031	$0.07508	$12,047,716	
Off-Peak	211,396,538	$0.07304	$15,440,604		211,396,538	$0.06579	$13,908,175	
Revenue from Energy Charges			$66,021,736				$61,074,418	
Revenue from Energy as % of Total			73.71%				69.65%	
AVERAGE RATE LIMITER - Summer ($/kWh)		$0.20969				$0.20651		
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
E-19	2,347	$400	$938,667	$13.14	2,347	$600	$1,408,000	$19.71
Rate V	1,495	$99	$147,810	$3.25	1,495	$120	$179,436	$3.94
Revenue from Customer Charges			$1,086,477				$1,587,436	
Revenue from Customer Chrg as % of Total			1.21%				1.81%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$89,568,085	Total Rev			$87,692,371	Total Rev
deviation above or below standard power factor of 85%							-2.09%	Change
OPTIONAL METER DATA		$0.98563	$30.00			$0.98563	$30.00	
ACCESS CHARGE ($/meter/day)		per day	per month			per day	per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Transmission Firm	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	42,881	$10.73	$460,112		42,881	$7.84	$336,091	
Part-Peak	45,820	$2.48	$113,635		45,820	$1.77	$80,930	
Maximum	49,898	$3.28	$163,665		49,898	$4.30	$214,756	
Winter								
Part-Peak	43,410	$0.00	$0		43,410	$0.00	$0	
Maximum	44,543	$3.28	$146,099		44,543	$4.30	$191,707	
Revenue from Demand Charges			$883,511				$823,485	
Revenue from Demand as % of Total			25.21%				26.13%	
ENERGY CHARGES - Non-FTA ($/kWh)								
Summer								
Peak	3,049,760	$0.10044	$306,318		3,049,760	$0.09552	$291,299	
Part-Peak	3,671,900	$0.09107	$334,400		3,671,900	$0.07664	$281,405	
Off-Peak	9,254,257	$0.06937	$641,968		9,254,257	$0.06537	$604,948	
Winter								
Part-Peak	6,295,939	$0.08713	$548,565		6,295,939	$0.06980	$439,442	
Off-Peak	9,329,031	$0.07255	$676,821		9,329,031	$0.06201	$578,467	
Revenue from Energy Charges			$2,508,072				$2,195,560	
Revenue from Energy as % of Total			71.56%				69.67%	
AVERAGE RATE LIMITER - Summer ($/kWh)		N/A				N/A		
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
E-19	100	$1,030	$102,974	$33.83	100	$1,200	$120,000	$39.43
Rate V	104	$99	$10,280	$3.25	104	$120	$12,480	$3.94
Revenue from Customer Charges			$113,254				$132,480	
Revenue from Customer Chrg as % of Total			3.23%				4.20%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$3,504,838	Total Rev			$3,151,525	Total Rev
deviation above or below standard power factor of 85%							-10.08%	Change
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)		$0.98563 per day	$30.00 per month			$0.98563 per day	$30.00 per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-20 Secondary Firm	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	3,131,295	$15.23	$47,689,625		3,131,295	$11.08	$34,679,705	
Part-Peak	3,177,541	$3.44	$10,930,740		3,177,541	$2.47	$7,843,846	
Maximum	3,293,036	$7.27	$23,940,375		3,293,036	$7.45	$24,519,689	
Winter								
Part-Peak	2,834,975	$2.06	$5,840,049		2,834,975	$1.04	$2,959,342	
Maximum	2,864,890	$7.27	$20,827,754		2,864,890	$7.45	$21,331,748	
Revenue from Demand Charges			$109,228,543				$91,334,330	
Revenue from Demand as % of Total			33.56%				30.83%	
ENERGY CHARGES ($/kWh)								
Summer								
Peak	305,199,983	$0.13185	$40,240,618		305,199,983	$0.12346	$37,679,767	
Part-Peak	317,366,387	$0.09508	$30,175,196		317,366,387	$0.08515	$27,024,650	
Off-Peak	745,413,583	$0.06700	$49,942,710		745,413,583	$0.06942	$51,743,820	
Winter								
Part-Peak	545,648,015	$0.08717	$47,564,137		545,648,015	$0.07615	$41,549,721	
Off-Peak	645,804,576	$0.07038	$45,451,726		645,804,576	$0.06712	$43,347,732	
Revenue from Energy Charges			$213,374,387				$201,345,691	
Revenue from Energy as % of Total			65.56%				67.96%	
AVERAGE RATE LIMITER - Summer ($/kWh)		$0.20580				$0.20092		
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE($/meter/day)	4,773	$600	$2,864,034	$19.71	4,773	$750	$3,580,043	$24.64
Revenue from Customer Charges			$2,864,034				$3,580,043	
Revenue from Customer Chrg as % of Total			0.88%				1.21%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$325,466,964	Total Rev			$296,260,064	Total Rev
deviation above or below standard power factor of 85%							-8.97%	Change
OPTIONAL METER DATA		$0.98563	$30.00			$0.98563	$30.00	
ACCESS CHARGE ($/meter/day)		per day	per month			per day	per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-20 Primary Firm	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	4,783,102	$11.88	$56,823,253		4,783,102	$10.44	$49,931,684	
Part-Peak	5,048,980	$2.72	$13,733,226		5,048,980	$2.41	$12,185,034	
Maximum	5,246,396	$5.04	$26,441,835		5,246,396	$6.11	$32,070,914	
Winter								
Part-Peak	4,586,848	$0.80	$3,669,478		4,586,848	$0.67	$3,075,054	
Maximum	4,654,951	$5.04	$23,460,954		4,654,951	$6.11	$28,455,448	
Revenue from Demand Charges			$124,128,746				$125,718,134	
Revenue from Demand as % of Total			26.35%				27.24%	
ENERGY CHARGES ($/kWh)								
Summer								
Peak	453,550,967	$0.12385	$56,172,287		453,550,967	$0.12613	$57,205,281	
Part-Peak	523,433,458	$0.09183	$48,066,894		523,433,458	$0.08527	$44,633,602	
Off-Peak	1,339,284,112	$0.06527	$87,415,074		1,339,284,112	$0.06763	$90,579,109	
Winter								
Part-Peak	875,241,485	$0.08266	$72,347,461		875,241,485	$0.07328	$64,139,360	
Off-Peak	1,154,103,499	$0.06832	$78,848,351		1,154,103,499	$0.06435	$74,265,398	
Revenue from Energy Charges			$342,850,068				$330,822,749	
Revenue from Energy as % of Total			72.79%				71.67%	
AVERAGE RATE LIMITER - Summer ($/kWh)		$0.20580				$0.20092		
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	5,042	$800	$4,033,603	$26.28	5,042	$1,000	$5,042,004	$32.85
Revenue from Customer Charges			$4,033,603				$5,042,004	
Revenue from Customer Chrg as % of Total			0.86%				1.09%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$471,012,417	Total Rev			$461,582,887	Total Rev
deviation above or below standard power factor of 85%							-2.00%	Change
OPTIONAL METER DATA		$0.98563	$30.00			$0.98563	$30.00	
ACCESS CHARGE ($/meter/day)		per day	per month			per day	per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-20 Transmission
Firm

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES ($/kW)								
Summer								
Peak	4,060,177	$9.72	$39,464,923		4,060,177	$9.44	$38,312,813	
Part-Peak	4,167,563	$2.11	$8,793,559		4,167,563	$2.11	$8,814,324	
Maximum	4,529,267	$3.18	$14,403,069		4,529,267	$3.18	$14,398,282	
Winter								
Part-Peak	3,820,257	$0.00	$0		3,820,257	$0.00	$0	
Maximum	3,947,263	$3.18	$12,552,298		3,947,263	$3.18	$12,548,126	
Revenue from Demand Charges			$75,213,849				$74,073,545	
Revenue from Demand as % of Total			23.32%				22.98%	
ENERGY CHARGES ($/kWh)								
Summer								
Peak	384,826,344	$0.08111	$31,213,265		384,826,344	$0.08819	$33,937,687	
Part-Peak	442,669,667	$0.07356	$32,562,781		442,669,667	$0.07076	$31,323,163	
Off-Peak	1,233,390,515	$0.05605	$69,131,538		1,233,390,515	$0.06036	$74,442,604	
Winter								
Part-Peak	728,780,455	$0.07039	$51,298,856		728,780,455	$0.06444	$46,965,860	
Off-Peak	1,053,393,784	$0.05863	$61,760,478		1,053,393,784	$0.05725	$60,308,341	
Revenue from Energy Charges			$245,966,918				$246,977,655	
Revenue from Energy as % of Total			76.26%				76.61%	
AVERAGE RATE LIMITER - Summer ($/kWh)		N/A				N/A		
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	1,334	$1,030	$1,373,275	$33.83	1,334	$1,005	$1,340,442	$33.02
Revenue from Customer Charges			$1,373,275				$1,340,442	
Revenue from Customer Chrg as % of Total			0.43%				0.42%	
POWER FACTOR ADJUSTMENT ($/kWh)		$0.00005				$0.00005		
per kWh charge or credit to be applicable per each 1%			$322,554,042	Total Rev			$322,391,642	Total Rev
deviation above or below standard power factor of 85%							-0.05%	Change
OPTIONAL METER DATA		$0.98563	$30.00			$0.98563	$30.00	
ACCESS CHARGE ($/meter/day)		per day	per month			per day	per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

SCHEDULE S TRANSMISSION	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
RESERVATION CHARGES ($/kW)							
Summer							
Contract Capacity (rate applies to 85%)	4,448,725	$0.72	$2,706,141	4,448,725	$0.74	$2,803,047	
Winter							
Contract Capacity (rate applies to 85%)	4,448,725	$0.72	$2,706,141	4,448,725	$0.74	$2,803,047	
Revenue from Reservation Charges			$5,412,282			$5,606,095	
Revenue from Reservation as % of Total			21.57%			21.80%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	8,984,894	$0.09534	$856,590	8,984,894	$0.09949	$893,917	
Part-Peak	12,264,304	$0.08771	$1,075,750	12,264,304	$0.08547	$1,048,287	
Off-Peak	60,917,575	$0.07006	$4,268,155	60,917,575	$0.07711	$4,697,266	
Winter							
Part-Peak	60,091,833	$0.08453	$5,079,480	60,091,833	$0.08040	$4,831,158	
Off-Peak	94,008,532	$0.07267	$6,831,485	94,008,532	$0.07461	$7,014,161	
Revenue from Energy Charges			$18,111,460			$18,484,788	
Revenue from Energy as % of Total			72.20%			71.90%	
CUSTOMER CHARGE ($/meter/mo.)							
Small-Single Phase (A-6)	0	$8.10	$0	0	$12.00	$0	
Small-Polyphase (A-6)	0	$12.00	$0	0	$18.00	$0	
Medium (>50 kW & <500 kW)	19	$93.46	$1,794	19	$120.00	$2,304	
Medium (>500 kW & <1000 kW)	408	$1,030.00	$420,240	408	$1,200.00	$489,600	
Large (>1000 kW)	1,104	$1,030.00	$1,137,120	1,104	$1,017.29	$1,123,083	
Reduced - Medium	77	$42.98	$3,309	77	$57.34	$4,415	
Revenue from Customer Charges			$1,562,464			$1,619,402	
Revenue from Customer Chrg as % of Total			6.23%			6.30%	
			$25,086,206			$25,710,285	Total Rev
						2.49%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

SCHEDULE S
PRIMARY

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
RESERVATION CHARGES ($/kW)							
Summer							
Contract Capacity (rate applies to 85%)	185,668	$1.57	$248,372	185,668	$2.32	$365,504	
Winter							
Contract Capacity (rate applies to 85%)	185,668	$1.57	$248,372	185,668	$2.32	$365,504	
Revenue from Reservation Charges			$496,744			$731,009	
Revenue from Reservation as % of Total			28.26%			38.14%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	567,829	$0.23462	$133,225	567,829	$0.26379	$149,785	
Part-Peak	649,312	$0.17936	$116,458	649,312	$0.16039	$104,145	
Off-Peak	2,565,947	$0.13059	$335,096	2,565,947	$0.12086	$310,112	
Winter							
Part-Peak	1,596,410	$0.16613	$265,219	1,596,410	$0.14062	$224,494	
Off-Peak	2,418,632	$0.13578	$328,408	2,418,632	$0.11850	$286,602	
Revenue from Energy Charges			$1,178,406			$1,075,139	
Revenue from Energy as % of Total			67.05%			56.10%	
CUSTOMER CHARGE ($/meter/mo.)							
Small-Single Phase (A-6)	0	$8.10	$0	0	$12.00	$0	
Small-Polyphase (A-6)	0	$12.00	$0	0	$18.00	$0	
Medium (>50 kW & <500 kW)	48	$93.46	$4,486	48	$120.00	$5,760	
Medium (>500 kW & <1000 kW)	72	$400.00	$28,800	72	$600.00	$43,200	
Large (>1000 kW)	60	$800.00	$48,000	60	$1,000.00	$60,000	
Reduced - Medium	24	$42.98	$1,032	24	$57.34	$1,376	
Revenue from Customer Charges			$82,318			$110,336	
Revenue from Customer Chrg as % of Total			4.68%			5.76%	
			$1,757,467			$1,916,484	Total Rev
						9.05%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

SCHEDULE S
SECONDARY

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT			
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
RESERVATION CHARGES ($/kW)							
Summer							
Contract Capacity (rate applies to 85%)	235,590	$1.61	$322,043	235,590	$2.34	$468,625	
Winter							
Contract Capacity (rate applies to 85%)	235,590	$1.61	$322,043	235,590	$2.34	$468,625	
Revenue from Reservation Charges			$644,085			$937,250	
Revenue from Reservation as % of Total			26.63%			37.29%	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	795,827	$0.24461	$194,669	795,827	$0.26500	$210,890	
Part-Peak	855,696	$0.18436	$157,755	855,696	$0.15988	$136,808	
Off-Peak	2,854,662	$0.13273	$378,885	2,854,662	$0.11977	$341,897	
Winter							
Part-Peak	2,558,321	$0.17261	$441,600	2,558,321	$0.14134	$361,604	
Off-Peak	4,190,929	$0.13820	$579,168	4,190,929	$0.11742	$492,113	
Revenue from Energy Charges			$1,752,079			$1,543,312	
Revenue from Energy as % of Total			72.45%			61.40%	
CUSTOMER CHARGE ($/meter/mo.)							
Small-Single Phase (A-6)	668	$8.10	$5,411	668	$12.00	$8,016	
Small-Polyphase (A-6)	928	$12.00	$11,136	928	$18.00	$16,704	
Medium (>50 kW & <500 kW)	18	$93.46	$1,682	18	$120.00	$2,160	
Medium (>500 kW & <1000 kW)	12	$275.00	$3,300	12	$412.50	$4,950	
Large (>1000 kW)	0	$600.00	$0	0	$750.00	$0	
Reduced - Medium	18	$42.98	$774	18	$57.34	$1,032	
Revenue from Customer Charges			$22,303			$32,862	
Revenue from Customer Chrg as % of Total			0.92%			1.31%	
			$2,418,466			$2,513,424	Total Rev
						3.93%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

A-10 Secondary
BUNDLED

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$3.55	$2.62	$0.00	$2.97	$9.14
Winter					
Maximum	$2.36	$0.00	$0.00	$2.97	$5.33
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Total	$0.01751	$0.08391	$0.01003	$0.00776	$0.11921
Winter					
Total	$0.01168	$0.06086	$0.01003	$0.00776	$0.09033

A-10 Primary
BUNDLED

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$2.91	$2.70	$0.00	$2.97	$8.58
Winter					
Maximum	$1.93	$0.00	$0.00	$2.97	$4.90
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Total	$0.01409	$0.08161	$0.00978	$0.00776	$0.11324
Winter					
Total	$0.00939	$0.05881	$0.00978	$0.00776	$0.08574

A-10 Transmission
BUNDLED

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$0.32	$3.05	$0.00	$2.97	$6.33
Winter					
Maximum	$0.20	$0.00	$0.00	$2.97	$3.17
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Total	$0.00135	$0.07969	$0.00943	$0.00776	$0.09824
Winter					
Total	$0.00090	$0.05748	$0.00943	$0.00776	$0.07558

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

A-10 Secondary
TOU

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$3.55	$2.62	$0.00	$2.97	$9.14
Winter					
Maximum	$2.36	$0.00	$0.00	$2.97	$5.33
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.01751	$0.10339	$0.01003	$0.00776	$0.13869
Part-Peak	$0.01751	$0.08420	$0.01003	$0.00776	$0.11951
Off-Peak	$0.01751	$0.07279	$0.01003	$0.00776	$0.10809
Winter					
Part-Peak	$0.01168	$0.06551	$0.01003	$0.00776	$0.09498
Off-Peak	$0.01168	$0.05637	$0.01003	$0.00776	$0.08583

A-10 Primary
TOU

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$2.91	$2.70	$0.00	$2.97	$8.58
Winter					
Maximum	$1.93	$0.00	$0.00	$2.97	$4.90
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.01409	$0.09914	$0.00978	$0.00776	$0.13077
Part-Peak	$0.01409	$0.08208	$0.00978	$0.00776	$0.11371
Off-Peak	$0.01409	$0.07149	$0.00978	$0.00776	$0.10312
Winter					
Part-Peak	$0.00939	$0.06247	$0.00978	$0.00776	$0.08940
Off-Peak	$0.00939	$0.05528	$0.00978	$0.00776	$0.08221

A-10 Transmission
TOU

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Maximum	$0.32	$3.05	$0.00	$2.97	$6.33
Winter					
Maximum	$0.20	$0.00	$0.00	$2.97	$3.17
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00135	$0.09645	$0.00943	$0.00776	$0.11499
Part-Peak	$0.00135	$0.07996	$0.00943	$0.00776	$0.09851
Off-Peak	$0.00135	$0.07012	$0.00943	$0.00776	$0.08867
Winter					
Part-Peak	$0.00090	$0.06094	$0.00943	$0.00776	$0.07903
Off-Peak	$0.00090	$0.05414	$0.00943	$0.00776	$0.07223

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

E-19 Secondary
FIRM

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$3.61	$7.78	N/A	$0.00	$11.40
Part-Peak	$0.97	$1.66	N/A	$0.00	$2.63
Maximum	$4.31	$0.00	N/A	$2.97	$7.28
Winter					
Part-Peak	$1.04	$0.00	N/A	$0.00	$1.04
Maximum	$4.31	$0.00	N/A	$2.97	$7.28
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Peak	$0.01196	$0.10029	$0.00947	$0.00773	$0.12945
Part-Peak	$0.00479	$0.06665	$0.00947	$0.00773	$0.08863
Off-Peak	$0.00239	$0.05240	$0.00947	$0.00773	$0.07200
Winter					
Part-Peak	$0.00407	$0.05771	$0.00947	$0.00773	$0.07899
Off-Peak	$0.00272	$0.04966	$0.00947	$0.00773	$0.06957

E-19 Primary
FIRM

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$2.78	$7.53	N/A	$0.00	$10.31
Part-Peak	$0.75	$1.62	N/A	$0.00	$2.37
Maximum	$3.28	$0.00	N/A	$2.97	$6.24
Winter					
Part-Peak	$0.78	$0.00	N/A	$0.00	$0.78
Maximum	$3.28	$0.00	N/A	$2.97	$6.24
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Peak	$0.00961	$0.10337	$0.00892	$0.00773	$0.12963
Part-Peak	$0.00384	$0.06678	$0.00892	$0.00773	$0.08727
Off-Peak	$0.00192	$0.05049	$0.00892	$0.00773	$0.06906
Winter					
Part-Peak	$0.00324	$0.05520	$0.00892	$0.00773	$0.07508
Off-Peak	$0.00216	$0.04699	$0.00892	$0.00773	$0.06579

E-19 Transmission
Firm

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$0.00	$7.84	N/A	$0.00	$7.84
Part-Peak	$0.00	$1.77	N/A	$0.00	$1.77
Maximum	$1.34	$0.00	N/A	$2.97	$4.30
Winter					
Part-Peak	$0.00	$0.00	N/A	$0.00	$0.00
Maximum	$1.34	$0.00	N/A	$2.97	$4.30
ENERGY CHARGES - Non-FTA ($/kWh)					
Summer					
Peak	$0.00000	$0.07882	$0.00896	$0.00773	$0.09552
Part-Peak	$0.00000	$0.05995	$0.00896	$0.00773	$0.07664
Off-Peak	$0.00000	$0.04868	$0.00896	$0.00773	$0.06537
Winter					
Part-Peak	$0.00000	$0.05311	$0.00896	$0.00773	$0.06980
Off-Peak	$0.00000	$0.04532	$0.00896	$0.00773	$0.06201

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

E-20 Secondary
Firm

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$3.65	$7.43	N/A	$0.00	$11.08
Part-Peak	$0.95	$1.52	N/A	$0.00	$2.47
Maximum	$4.27	$0.00	N/A	$3.18	$7.45
Winter					
Part-Peak	$1.04	$0.00	N/A	$0.00	$1.04
Maximum	$4.27	$0.00	N/A	$3.18	$7.45
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.01148	$0.09503	$0.00920	$0.00774	$0.12346
Part-Peak	$0.00459	$0.06362	$0.00920	$0.00774	$0.08515
Off-Peak	$0.00230	$0.05018	$0.00920	$0.00774	$0.06942
Winter					
Part-Peak	$0.00394	$0.05526	$0.00920	$0.00774	$0.07615
Off-Peak	$0.00263	$0.04755	$0.00920	$0.00774	$0.06712

E-20 Primary
Firm

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$2.39	$8.05	N/A	$0.00	$10.44
Part-Peak	$0.65	$1.76	N/A	$0.00	$2.41
Maximum	$2.93	$0.00	N/A	$3.18	$6.11
Winter					
Part-Peak	$0.67	$0.00	N/A	$0.00	$0.67
Maximum	$2.93	$0.00	N/A	$3.18	$6.11
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00768	$0.10217	$0.00856	$0.00772	$0.12613
Part-Peak	$0.00307	$0.06592	$0.00856	$0.00772	$0.08527
Off-Peak	$0.00154	$0.04982	$0.00856	$0.00772	$0.06763
Winter					
Part-Peak	$0.00255	$0.05446	$0.00856	$0.00772	$0.07328
Off-Peak	$0.00170	$0.04637	$0.00856	$0.00772	$0.06435

E-20 Transmission
Firm

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$0.00	$9.44	N/A	$0.00	$9.44
Part-Peak	$0.00	$2.11	N/A	$0.00	$2.11
Maximum	$0.00	$0.00	N/A	$3.18	$3.18
Winter					
Part-Peak	$0.00	$0.00	N/A	$0.00	$0.00
Maximum	$0.00	$0.00	N/A	$3.18	$3.18
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.07298	$0.00750	$0.00771	$0.08819
Part-Peak	$0.00000	$0.05555	$0.00750	$0.00771	$0.07076
Off-Peak	$0.00000	$0.04514	$0.00750	$0.00771	$0.06036
Winter					
Part-Peak	$0.00000	$0.04923	$0.00750	$0.00771	$0.06444
Off-Peak	$0.00000	$0.04204	$0.00750	$0.00771	$0.05725

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

SCHEDULE S
TRANSMISSION

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
Summer					
Contract Capacity (rate applies to 85%)	$0.20	$0.17	$0.00	$0.36	$0.74
Winter					
Contract Capacity (rate applies to 85%)	$0.20	$0.17	$0.00	$0.36	$0.74
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.07092	$0.00908	$0.01949	$0.09949
Part-Peak	$0.00000	$0.05690	$0.00908	$0.01949	$0.08547
Off-Peak	$0.00000	$0.04854	$0.00908	$0.01949	$0.07711
Winter					
Part-Peak	$0.00000	$0.05182	$0.00908	$0.01949	$0.08040
Off-Peak	$0.00000	$0.04604	$0.00908	$0.01949	$0.07461

SCHEDULE S
PRIMARY

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
Summer					
Contract Capacity (rate applies to 85%)	$1.78	$0.17	$0.00	$0.36	$2.32
Winter					
Contract Capacity (rate applies to 85%)	$1.78	$0.17	$0.00	$0.36	$2.32
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.14291	$0.08894	$0.01244	$0.01949	$0.26379
Part-Peak	$0.05716	$0.07129	$0.01244	$0.01949	$0.16039
Off-Peak	$0.02858	$0.06034	$0.01244	$0.01949	$0.12086
Winter					
Part-Peak	$0.04407	$0.06461	$0.01244	$0.01949	$0.14062
Off-Peak	$0.02938	$0.05718	$0.01244	$0.01949	$0.11850

SCHEDULE S
SECONDARY

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
Summer					
Contract Capacity (rate applies to 85%)	$1.78	$0.20	$0.00	$0.36	$2.34
Winter					
Contract Capacity (rate applies to 85%)	$1.78	$0.20	$0.00	$0.36	$2.34
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.14291	$0.09096	$0.01163	$0.01949	$0.26500
Part-Peak	$0.05716	$0.07159	$0.01163	$0.01949	$0.15988
Off-Peak	$0.02858	$0.06006	$0.01163	$0.01949	$0.11977
Winter					
Part-Peak	$0.04407	$0.06614	$0.01163	$0.01949	$0.14134
Off-Peak	$0.02938	$0.05691	$0.01163	$0.01949	$0.11742

EXHIBIT B

PRO FORMA TARIFF LANGUAGE FOR

STANDBY SERVICE SCHEDULE S

The Settling Parties agree to modify Special Conditions 1 and 2 of the Schedule S tariff to read as provided herein. These modifications will replace the current ratchet provisions for standby customer Reservation Capacity with an annual review procedure (Special Condition 1), and will replace the current method of administering and billing the Reactive Demand Charge with a new system that includes provisions for exemptions from this charge for customers who are required or agree to comply with voltage regulation orders issued by PG&E (as described in the revised Special Condition 2).

The Settling Parties also agree that it is reasonable to increase the Reactive Demand Charge rate under Schedule S from its current level of $0.15 to $0.35 per kVAR, except in those instances and for those customers where the Reactive Demand Charge is waived subject to the provisions of the revised Special Condition 2. The Settling Parties also agree that the revised Reactive Demand Charge provisions will be the only reactive power-related charges that are billed under Schedule S. Accordingly, the Settling Parties agree that Special Condition 8 ("Power Factor Adjustment") should be removed from the Schedule S tariff.

The Settling Parties agree further that both real and reactive power demands should continue to be measured on a 15-minute basis, and that this standard should be added to the Applicability section of the Schedule S tariff, using the same definitions that are already part of the Schedule A-10, E-19 and E-20 tariffs:

> **Definition of Maximum Demand**: The real (kW) and reactive (kVAR) demands billed under this tariff will be averaged over 15-minute intervals. "Maximum demand" (real and reactive) will be the highest of all of the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals.

The Settling Parties agree to modify Special Conditions 1 and 2 of the standby tariff to read as follows:

1. RESERVATION CAPACITY:

The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service as amended consistent with this Special Condition 1. For new or revised contracts, the Reservation Capacity shall be set as initially determined by the customer, except that during the first 12 month period following the date of initial specification, PG&E may review the specified Reservation Capacity on a monthly basis and make adjustments as warranted (consistent with the criteria specified below). Thereafter, PG&E may perform an annual review of the most recent 12 months of actual customer operation and make prospective adjustments to the Reservation Capacity as warranted and consistent with customer's historic operations. Any such adjusted Reservation Capacity shall be effective for a minimum of 12 months unless a documented material change of operation is provided to PG&E by customer. Customer may provide PG&E with documentation of such material changes in operations as might call for an adjusted Reservation Capacity at any time. Upon receipt and review of such documentation, PG&E shall revise the Reservation Capacity effective for the billing period immediately following receipt of the documentation.

For purposes of the subsequent annual contract reviews and any resulting adjustment to the Reservation Capacity, the following criteria shall apply:

a. For those customers who operate sufficient non-utility generating capacity so as to ordinarily satisfy all of the electric energy requirements at their site and so do not ordinarily require any service through facilities owned by PG&E, the Reservation Capacity shall not be any greater than the customer's hourly peak demand established during the most recent 12 months of actual customer operation;

b. For customers with electric loads that exceed the capability of their non-utility generation so as to require the regular provision of supplemental power service through facilities owned by PG&E, the Reservation Capacity determination shall consider the number and size of the customer's non-utility generating unit(s), the outage diversity of the non-utility generating units serving the customer's load and any reduction of customer load commensurate with non-utility generator capacity outages; and

For customers taking Extended Outage Service under Special Condition 9 to this tariff, the Reservation Capacity recorded during the period of Extended Outage Service shall be considered only for purposes of billing customer for Extended Outage Service, and shall not be considered in PG&E's determination of customer Reservation Capacity for purposes of other standby service taken under this tariff outside of Extended Outage Service periods. See Special Condition 7 of this tariff for the definition of Reservation Capacity for Supplemental Standby Service customers.

2. REACTIVE DEMAND CHARGE:

When the customer's non-utility generation equipment is operated in parallel with PG&E's system, the customer will design and attempt to operate its facilities in such a way that the reactive current requirements of that portion of the customer's load which is ordinarily supplied from the customer's generation is not supplied at any time from PG&E's system. If the customer does place a reactive demand on PG&E's system in any month, the customer's monthly bill will be adjusted as follows:

a. A monthly Reactive Demand Charge power factor is computed from the ratio of lagging maximum reactive kilovolt-amperes consumed in the month to the Reservation Capacity kilowatts. This power factor is rounded to the nearest whole percent.

b. If the calculated monthly Reactive Demand Charge power factor is below 95 percent, the total monthly bill will be increased by the product of the maximum reactive kilovolt-amperes consumed in the month and the Reactive Demand Charge rate.

Those customers operating synchronous generators who are otherwise obligated to comply with PG&E switching center voltage orders are exempt from the Reactive Demand Charge, provided that customer is in compliance with all valid PG&E switching center voltage orders. Those customers operating synchronous generators who are not otherwise obligated to comply with PG&E switching center voltage orders may elect to comply with voltage orders on a voluntary basis and thereby receive the same exemption from the Reactive Demand Charge as is received by customers subject to mandatory voltage order obligations.

A customer who is operating under PG&E switching center voltage orders will become exempt from the Reactive Demand Charge after providing PG&E with the following written information:

a. Notification requesting an exemption including the name, address, and telephone number of the party requesting the exemption;

b. The location, telephone number, electronic mail address and Fax number of the entity to which PG&E switching center orders are to be transmitted; and

c. The generator equipment limits for operating voltages and plus and minus VARs.

Customers operating synchronous generators subject to exemption from paying the Reactive Demand Charge must comply with valid PG&E switching center voltage orders, as defined below for the purposes of this Special Condition 2. Upon request, the customer shall provide PG&E with written documentation sufficient to confirm customer's compliance with valid PG&E switching center voltage orders. Failure of the customer to comply with a valid PG&E switching center voltage order shall result in the following actions by PG&E:

a. On the initial noncompliance occurrence or an occurrence of noncompliance following the imposition of a penalty, PG&E will provide to the customer in writing, through U.S.

or electronic mail, the date and nature of the noncompliance and notice that another failure to comply within the next 12 months will result in assessment of a penalty.

b. On any second or further event of noncompliance within 12 months of the prior noncompliance occurrence, a penalty will be billed to the account, equal to the lesser of the number of months since the last noncompliance penalty and the number 12, multiplied by the highest created Reactive Demand in the most recent noncompliance period, multiplied by the current Reactive Demand Charge rate.

c. Customer eligibility for the exemption shall not be interrupted after a subsequent noncompliance occurrence (after a prior warning has been issued). However, a penalty for noncompliance as described here will be billed to the account.

A valid PG&E switching center voltage order shall specify the requested operating voltage, as measured at the customer's generator terminals (or some other mutually agreeable metering location), and shall request operation of the customer's generator within a power factor range that is no stricter than: (1) the customer's power factor range obligation as specified in a contractual agreement (if any); (2) the minimum power factor range specified by the applicable CAISO tariff; or (3) the customer specified generator equipment limits.

Notwithstanding any other provision of this Special Condition 2, a valid PG&E switching center voltage order request shall ordinarily allow operation of the customer's generator within a power factor range that does not require the generator to reduce its MW output in order to comply with such request, with exceptions only to occur on an emergency basis, such as the unexpected loss of a major transmission line or large generation facility, or under extreme weather and/or system peak load conditions. No such exceptional voltage order request need be treated as valid if compliance with such a request would conflict with any protections that might be afforded to the customer's load in those instances where a valid Essential Use Customer designation applies to the load at the site.

(END OF APPENDIX E)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON AGRICULTURAL RATE DESIGN ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Agricultural Rate Design Settlement Agreement (Settling Parties, AG Settlement) agree on a mutually acceptable outcome to the AG rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This AG Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses AG rate issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this AG Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this AG Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- Agricultural Energy Consumers Association (AECA)
- California Farm Bureau Federation (CFBF)
- California Rice Millers (CRM)
- Cogeneration Association of California (CAC)
- Energy Producers and Users Coalition (EPUC)
- Pacific Gas and Electric Company (PG&E)

III. SETTLEMENT CONDITIONS

This AG Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on AG rate design, subject to the conditions set forth below:

1. This AG Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This AG Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.
2. This AG Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This AG Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this AG Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this AG Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
5. This AG Settlement may be amended or changed only by a written agreement signed by the Settling Parties.
6. The Settling Parties shall jointly request Commission approval of this AG Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the

requested approval.

7. The Settling Parties intend the AG Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the agricultural rate design agreed to herein. In the event the Commission rejects or modifies this AG Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, the Settling Parties to this AG Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. AGRICULTURAL SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the rate design for the AG class embodied in this AG Settlement takes the revenue allocation reached for that class in the February 9 Settlement and ensures that it is fully recovered through AG rates in a manner that is just and reasonable, in the public interest, and that reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which is based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this AG Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the AG class and will differ from the rates presented herein. However, these actual rates shall be based on the AG rate structure described below.

The AG class consists of Schedules AG-1, AG-R, AG-V, AG-4, and AG-5. Schedule E-37 for oil pumping customers is combined with the agricultural rate design for Schedule AG-5B. Schedule AG-ICE is treated separately from conventional agricultural revenue allocation and rate design, and is not part of this settlement unless specifically included. Illustrative allocation to these schedules is set forth in Exhibit A and illustrative rates are set forth in Exhibit B to this AG Settlement.

The Settling Parties agree that all testimony served prior to the date of this AG Settlement that addresses the issues resolved by this AG Settlement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree that this AG Settlement resolves all AG rate design issues in A.06-03-005.

VI. AGRICULTURAL RATE DESIGN SETTLEMENT TERMS

A. Illustrative bundled revenues and average settlement rates for the AG rate schedules after revenue allocation and rate design are presented in Exhibit A. The allocations and average rates were developed to collect the revenue allocated to the AG customer class set forth in Tables 5-A and 5-B of the February 9 Settlement based on estimated March 2007 revenue requirements. Adopted revenue requirements in effect upon settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual average rates and allocated revenues may vary from those shown in Exhibit A when the Phase 2 rate changes are implemented.

B. The Settling Parties agree that the basic rate designs for each of the applicable AG rate schedules will be updated upon settlement implementation using the methods underlying development of the illustrative settlement rates for Schedules AG-1, AG-R, AG-V, AG-4, AG-5, and E-37 presented in Exhibit B. These methods reflect approaches proposed by PG&E in its Rate Update testimony, Exhibit (PG&E-4), filed June 26, 2006, as updated to incorporate the revenue allocation proposals and updated marginal costs agreed upon in the February 9 Settlement, and other revenue allocation or rate design revisions, including a general widening of TOU energy charge differentials and mitigation of summer maximum demand charges where necessary.

C. Customer charges for AG-A, AG-B, and AG-C rates shall generally be moderately increased as shown in Exhibit B. The fixed monthly customer charges currently at $12 for AG-A and $16 for AG-B rates shall increase 20 percent to $14.40 and $19.20 per month, respectively. The fixed monthly customer charges of $16 for AG-5B and $54 for AG-5C shall increase to $30 and $160 per month, respectively. The fixed monthly customer charge of $54 for AG-4C shall increase 20 percent to $64.80. This settlement does not revise Schedule AG-ICE customer charges.

D. Ongoing Time-of-Use (TOU) meter charges applicable to voluntary AG TOU rate schedules will no longer be applied as each customer's Advanced Meter Infrastructure (AMI) meter is installed and used for billing. This provision also covers Schedule AG-ICE.

E. PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15 and 1-16, shall be adopted for Direct Access and Community Choice Aggregation service.

F. The illustrative rates shown in Exhibit B are developed to collect the same revenue allocated to the agricultural class that was used for the February 9 Settlement. The actual rates developed to implement this decision will vary based on the then current adopted revenue requirements.

G. Timing of Rate Changes: Certain elements of this Agricultural Settlement require employee training and/or changes to PG&E systems beyond a normal change to a rate value. These changes include discontinuing the ongoing TOU meter charge in item D, and revision of the franchise fee surcharge calculation in item E. These systems and program changes will be implemented by PG&E diligently as time permits and in a manner consistent with maintaining the secure, smooth operations of the systems involved. The Settling Parties recognize that some initiatives could take several months to implement.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this Agricultural Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This AG Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the AG Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this AG Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Agricultural Energy Consumers Association

/s/

By: Dan Geis

Title: Assistant Executive Director

Date: May 3, 2007

California Farm Bureau Federation

/s/

By: Ron Liebert

Title: Associate Counsel

Date: May 3, 2007

California Rice Millers

/s/

By: Paul Kerkorian
Utility Cost Management LLC

Title: Representative

Date: May 3, 2007

Cogeneration Association of California

/s/

By: Nora Sheriff

Title: Counsel

Date: May 3, 2007

Energy Producers and Users Coalition

/s/

By: Nora Sheriff

Title: Counsel

Date: May 3, 2007

Pacific Gas and Electric Company

/s/

By: Dan Pease

Title: Manager, Electric Rates

Date: May 3, 2007

Agricultural Rate Design Settlement

Exhibit A

Agricultural Bundled Intra Class Revenue Allocation

Schedule	Estimated 3/1/07 Revenue ($000)	Estimated 3/1/07 Avg Rate ($/kWh)	Illustrative Revenue ($000)	Illustrative Average Rate ($/kWh)	Percent Change
AG-1A	49,418	0.29026	49,788	0.29244	0.75%
AG-RA	5,082	0.20058	5,234	0.20660	3.00%
AG-VA	4,474	0.20245	4,608	0.20852	3.00%
AG-4A	22,174	0.19867	22,840	0.20463	3.00%
AG-5A	11,220	0.16295	11,557	0.16784	3.00%
AG-1B	49,146	0.20044	49,515	0.20194	0.75%
AG-RB	3,995	0.17155	4,075	0.17498	2.00%
AG-VB	2,288	0.17003	2,334	0.17343	2.00%
AG-4B	43,858	0.16023	44,735	0.16343	2.00%
AG-4C	6,448	0.16908	6,641	0.17415	3.00%
AG-5B	334,035	0.10260	351,622	0.10800	5.27%
AG-5C	32,884	0.09796	34,615	0.10312	5.27%
Total Bundled Ag	565,022	0.12328	587,564	0.12819	3.99%

Agricultural Rate Design Settlement

Exhibit B

Illustrative Agricultural Rate Design

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 1A	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	2,442,533	$3.12	7,621,555		2,442,533	$4.74	11,565,736	
Winter								
Maximum	2,437,889	$2.86	6,977,030		2,437,889	$0.88	2,153,539	
Revenue from Demand Charges			14,598,584				13,719,276	
Revenue from Demand as % of Total			29.54%				27.56%	
ENERGY CHARGE								
Summer								
Total	125,601,265	$0.17708	22,241,401		125,601,265	$0.18962	23,816,711	
Winter								
Total	44,648,574	$0.17708	7,906,344		44,648,574	$0.14887	6,646,651	
Revenue from Energy Charges			30,147,745				30,463,362	
Revenue from Energy as % of Total			61.01%				61.19%	
CUSTOMER CHARGE ($/meter/mo,)				($/meter/day)				($/meter/day)
Ag 1A	389,267	$12.00	4,671,200	.39425	389,267	$14.40	5,605,439	.47310
Revenue from Customer Charges			4,671,200				5,605,439	
Revenue from Customer Chrg as % of Total			9.45%				11.26%	
			49,417,529	Total Rev			49,788,077	Total Rev
							0.75%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG RA	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	269,538	$3.17	854,363		269,538	$4.42	1,190,208	
Winter								
Maximum	269,538	$2.89	779,735		269,538	$0.67	181,259	
Revenue from Demand Charges			1,634,098				1,371,466	
Revenue from Demand as % of Total			32.16%				26.20%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	1,218,647	$0.38655	471,067		1,218,647	$0.36888	449,534	
Off-Peak	18,217,515	$0.10373	1,889,633		18,217,515	$0.12604	2,296,074	
Winter								
Part-Peak	2,168,980	$0.09885	214,410		2,168,980	$0.12974	281,400	
Off-Peak	3,729,796	$0.08223	306,685		3,729,796	$0.10786	402,288	
Revenue from Energy Charges			2,881,795				3,429,296	
Revenue from Energy as % of Total			56.71%				65.52%	
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
Ag RA	30,096	$12.00	361,152	.39425	30,096	$14.40	433,382	.47310
Revenue from Customer Charges			361,152				433,382	
Revenue from Customer Chrg as % of Total			7.11%	($/meter/day)			8.28%	($/meter/day)
METER CHARGE ($/meter/mo.)	30,096	$6.80	204,653	.22341	30,096	$0.00	0	.00000
Revenue from Meter Charges			204,653				0	
Revenue from Meter Chrg as % of Total			4.03%				0.00%	
			5,081,697	Total Rev			5,234,145	Total Rev
							3.00%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG VA	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	233,088	$3.17	738,822		233,088	$4.44	1,035,651	
Winter								
Maximum	233,107	$2.89	674,342		233,107	$0.71	164,380	
Revenue from Demand Charges			1,413,164				1,200,031	
Revenue from Demand as % of Total			31.59%				26.04%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	1,569,246	$0.37931	595,224		1,569,246	$0.34144	535,807	
Off-Peak	15,170,906	$0.09962	1,511,339		15,170,906	$0.12339	1,872,001	
Winter								
Part-Peak	2,078,969	$0.09672	201,085		2,078,969	$0.13008	270,429	
Off-Peak	3,279,582	$0.08038	263,624		3,279,582	$0.10823	354,938	
Revenue from Energy Charges			2,571,272				3,033,175	
Revenue from Energy as % of Total			57.47%				65.82%	
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
Ag VA	26,035	$12.00	312,422	.39425	26,035	$14.40	374,906	.47310
Revenue from Customer Charges			312,422				374,906	
Revenue from Customer Chrg as % of Total			6.98%				8.14%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	26,035	$6.80	177,039	.22341	26,035	$0.00	0	.00000
Revenue from Meter Charges			177,039				0	
Revenue from Meter Chrg as % of Total			3.96%				0.00%	
			4,473,897	Total Rev			4,608,113	Total Rev
							3.00%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 4A	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	1,175,788	$3.17	3,729,217		1,175,788	$4.42	5,194,413	
Winter								
Maximum	1,175,819	$2.90	3,415,436		1,175,819	$0.62	730,922	
Revenue from Demand Charges			7,144,653				5,925,335	
Revenue from Demand as % of Total			32.22%				25.94%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	9,187,455	$0.38035	3,494,472		9,187,455	$0.27459	2,522,745	
Off-Peak	77,801,797	$0.09060	7,048,943		77,801,797	$0.12522	9,742,599	
Winter								
Part-Peak	8,492,966	$0.09744	827,514		8,492,966	$0.12990	1,103,236	
Off-Peak	16,131,698	$0.08109	1,308,193		16,131,698	$0.10818	1,745,193	
Revenue from Energy Charges			12,679,122				15,113,774	
Revenue from Energy as % of Total			57.18%				66.17%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	125,034	$12.00	1,500,414	.39425	125,034	$14.40	1,800,497	.47310
Revenue from Customer Charges			1,500,414				1,800,497	
Revenue from Customer Chrg as % of Total			6.77%				7.88%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	125,034	$6.80	850,234	.22341	125,034	$0.00	0	.00000
Revenue from Meter Charges			850,234				0	
Revenue from Meter Chrg as % of Total			3.83%				0.00%	
			22,174,423	Total Rev			22,839,606	Total Rev
							3.00%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 5A	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp)								
Summer								
Maximum	296,530	$6.97	2,066,547		296,530	$7.45	2,209,024	
Winter								
Maximum	296,539	$6.97	2,066,611		296,539	$1.25	369,466	
Revenue from Demand Charges			4,133,157				2,578,490	
Revenue from Demand as % of Total			36.84%				22.31%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	8,424,481	$0.27630	2,327,692		8,424,481	$0.21617	1,821,159	
Off-Peak	40,111,796	$0.06830	2,739,439		40,111,796	$0.11182	4,485,202	
Winter								
Part-Peak	7,831,216	$0.07476	585,434		7,831,216	$0.11740	919,349	
Off-Peak	12,490,058	$0.06241	779,510		12,490,058	$0.10016	1,250,958	
Revenue from Energy Charges			6,432,074				8,476,668	
Revenue from Energy as % of Total			57.33%	($/meter/day)			73.35%	($/meter/day)
CUSTOMER CHARGE ($/meter/day)	34,846	$12.00	418,151	.39425	34,846	$14.40	501,781	.47310
Revenue from Customer Charges			418,151				501,781	
Revenue from Customer Chrg as % of Total			3.73%				4.34%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	34,846	$6.80	236,952	.22341	34,846	$0.00	0	.00000
Revenue from Meter Charges			236,952				0	
Revenue from Meter Chrg as % of Total			2.11%				0.00%	
			11,220,335	Total Rev			11,556,939	Total Rev
							3.00%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 1B	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT) Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Maximum	1,059,871	$6.06	6,420,785		1,059,871	$7.28	7,720,841	
Winter								
Maximum	1,001,980	$4.19	4,199,439		1,001,980	$1.43	1,432,436	
Revenue from Demand Charges			10,620,224				9,153,277	
Revenue from Demand as % of Total			21.61%				18.49%	
ENERGY CHARGE								
Summer	180,925,580	$0.15101	27,321,573		180,925,580	$0.16665	30,150,856	
Winter	64,270,180	$0.15101	9,705,440		64,270,180	$0.13090	8,413,124	
Revenue from Energy Charges			37,027,014				38,563,979	
Revenue from Energy as % of Total			75.34%				77.88%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	93,678	$16.00	1,498,847	.52567	93,678	$19.20	1,798,616	.63080
Revenue from Customer Charges			1,498,847				1,798,616	
Revenue from Customer Chrg as % of Total			3.05%				3.63%	
			49,146,084	Total Rev			49,515,872	Total Rev
							0.75%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($0.82)				($0.85)		
Winter		($0.70)				($0.20)		

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG RB	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	49,627	$3.52	174,726		49,627	$2.50	124,067	
Maximum	124,212	$5.32	661,214		124,212	$6.10	757,151	
Winter								
Maximum	88,512	$5.05	447,418		88,512	$1.17	103,804	
Revenue from Demand Charges			1,283,357				985,021	
Revenue from Demand as % of Total			32.12%				24.17%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	740,310	$0.31854	235,819		740,310	$0.34300	253,929	
Off-Peak	17,813,827	$0.10365	1,846,457		17,813,827	$0.12187	2,170,884	
Winter								
Part-Peak	1,685,887	$0.10121	170,629		1,685,887	$0.11417	192,482	
Off-Peak	3,048,421	$0.08344	254,359		3,048,421	$0.09652	294,246	
Revenue from Energy Charges			2,507,264				2,911,541	
Revenue from Energy as % of Total			62.76%	($/meter/day)			71.45%	($/meter/day)
CUSTOMER CHARGE ($/meter/day)	9,300	$16.00	148,800	.52567	9,300	$19.20	178,560	.63080
Revenue from Customer Charges			148,800				178,560	
Revenue from Customer Chrg as % of Total			3.72%				4.38%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	9,300	$6.00	55,800	.19713	9,300	$0.00	0	.00000
Revenue from Meter Charges			55,800				0	
Revenue from Meter Chrg as % of Total			1.40%				0.00%	
			3,995,221	Total Rev			4,075,122	Total Rev
							2.00%	Ave Rate % Chg
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($0.72)				($0.57)		
Winter		($0.85)				($0.19)		

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG VB	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	40,599	$3.49	141,521		40,599	$2.50	101,497	
Maximum	68,379	$5.33	364,329		68,379	$6.09	416,661	
Winter								
Maximum	55,476	$4.39	243,419		55,476	$1.16	64,101	
Revenue from Demand Charges			749,270				582,258	
Revenue from Demand as % of Total			32.74%				24.94%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	560,114	$0.28690	160,694		560,114	$0.31194	174,723	
Off-Peak	10,028,985	$0.09975	1,000,360		10,028,985	$0.11772	1,180,577	
Winter								
Part-Peak	1,179,446	$0.10004	117,987		1,179,446	$0.11204	132,146	
Off-Peak	1,690,548	$0.08271	139,817		1,690,548	$0.09468	160,059	
Revenue from Energy Charges			1,418,858				1,647,505	
Revenue from Energy as % of Total			62.00%				70.56%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	5,471	$16.00	87,530	.52567	5,471	$19.20	105,036	.63080
Revenue from Customer Charges			87,530				105,036	
Revenue from Customer Chrg as % of Total			3.82%				4.50%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	5,471	$6.00	32,824	.19713	5,471	$0.00	0	.00000
Revenue from Meter Charges			32,824				0	
Revenue from Meter Chrg as % of Total			1.43%				0.00%	
			2,288,481	Total Rev			2,334,800	Total Rev
							2.02%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($0.72)				($0.59)		
Winter		($0.75)				($0.18)		

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 4B	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Peak	924,975	$3.46	3,200,460		924,975	$3.32	3,073,390	
Maximum	1,219,459	$5.47	6,669,432		1,219,459	$5.88	7,175,015	
Winter								
Maximum	1,037,819	$4.44	4,607,472		1,037,819	$1.26	1,312,152	
Revenue from Demand Charges			14,477,363				11,560,558	
Revenue from Demand as % of Total			33.01%				25.93%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	28,521,445	$0.23834	6,797,816		28,521,445	$0.19445	5,545,860	
Off-Peak	183,685,180	$0.08511	15,633,987		183,685,180	$0.10799	19,835,336	
Winter								
Part-Peak	26,041,637	$0.09246	2,407,938		26,041,637	$0.10778	2,806,740	
Off-Peak	35,478,767	$0.07660	2,717,804		35,478,767	$0.09163	3,250,958	
Revenue from Energy Charges			27,557,545				31,438,895	
Revenue from Energy as % of Total			62.83%				70.50%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	82,946	$16.00	1,327,142	.52567	82,946	$19.20	1,592,570	.63080
Revenue from Customer Charges			1,327,142				1,592,570	
Revenue from Customer Chrg as % of Total			3.03%				3.57%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	82,946	$6.00	497,678	.19713	82,946	$0.00	0	.00000
Revenue from Meter Charges			497,678				0	
Revenue from Meter Chrg as % of Total			1.13%				0.00%	
			43,857,985	Total Rev			44,591,087	Total Rev
							1.67%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	1,234	($0.91)	(1,127)		1,234	($0.67)	(830)	
Winter	521	($1.18)	(615)		521	($0.20)	(106)	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 5B	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT) Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	4,905,455	$3.37	16,523,530		4,905,455	$6.61	32,449,109	
Maximum	5,613,283	$10.18	57,155,507		5,613,283	$9.81	55,065,590	
Winter								
Maximum	4,852,540	$8.42	40,863,230		4,852,540	$3.58	17,361,565	
Revenue from Demand Charges			114,542,268				104,876,264	
Revenue from Demand as % of Total			33.56%				29.39%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	395,895,241	$0.16412	64,973,214		395,895,241	$0.15328	60,680,862	
Off-Peak	1,744,861,069	$0.05544	96,734,557		1,744,861,069	$0.06440	112,369,394	
Winter								
Part-Peak	457,443,207	$0.06152	28,143,909		457,443,207	$0.07968	36,450,956	
Off-Peak	657,560,564	$0.05138	33,783,626		657,560,564	$0.05806	38,178,326	
Revenue from Energy Charges			223,635,307				247,679,537	
Revenue from Energy as % of Total			65.53%				69.42%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	141,280	$16.00	2,260,487	.52567	141,280	$30.00	4,238,412	.98563
Revenue from Customer Charges			2,260,487				4,238,412	
Revenue from Customer Chrg as % of Total			0.66%				1.19%	
METER CHARGE ($/meter/day)				($/meter/day)				($/meter/day)
	141,280	$6.00	847,682	.19713	141,280	$0.00	0	.00000
Revenue from Meter Charges			847,682				0	
Revenue from Meter Chrg as % of Total			0.25%				0.00%	
			334,034,678	Total Rev			351,581,642	Total Rev
							5.25%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	609,988	($1.46)	(892,319)		609,988	($1.18)	(721,808)	
Winter	498,602	($1.24)	(619,013)		498,602	($0.13)	(66,903)	
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	450,352	($7.55)	(3,398,002)		450,352	($7.24)	(3,258,805)	
Winter	377,244	($6.21)	(2,341,732)		377,244	($3.09)	(1,165,054)	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 4C	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	89,131	$9.17	817,058		89,131	$7.69	685,802	
Part-Peak	144,352	$1.97	284,150		144,352	$1.46	211,212	
Maximum	237,582	$2.18	518,084		237,582	$2.75	654,456	
Winter								
Part-Peak	129,157	$0.60	78,032		129,157	$0.29	37,625	
Maximum	171,054	$0.88	150,172		171,054	$1.32	226,450	
Revenue from Demand Charges			1,847,495				1,815,545	
Revenue from Demand as % of Total			28.65%				27.34%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	3,207,834	$0.15208	487,839		3,207,834	$0.17791	570,704	
Part Peak	4,449,308	$0.10612	472,157		4,449,308	$0.10692	475,706	
Off-Peak	20,116,316	$0.07829	1,574,888		20,116,316	$0.08184	1,646,241	
Winter								
Part-Peak	3,443,440	$0.09625	331,439		3,443,440	$0.08979	309,199	
Off-Peak	6,919,004	$0.07945	549,701		6,919,004	$0.07874	544,805	
Revenue from Energy Charges			3,416,024				3,546,655	
Revenue from Energy as % of Total			52.98%	($/meter/day)			53.40%	($/meter/day)
CUSTOMER CHARGE ($/meter/day)	19,740	$54.00	1,065,960	1.77413	19,740	$64.80	1,279,152	2.12895
Revenue from Customer Charges			1,065,960				1,279,152	
Revenue from Customer Chrg as % of Total			16.53%	($/meter/day)			19.26%	($/meter/day)
METER CHARGE ($/meter/day)	19,740	$6.00	118,440	.19713	19,740	$0.00	0	.00000
Revenue from Meter Charges			118,440				0	
Revenue from Meter Chrg as % of Total			1.84%				0.00%	
			6,447,919	Total Rev			6,641,352	Total Rev
							3.00%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($1.16)				($0.89)		
Winter		($0.05)				($0.17)		
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($3.01)				($4.86)		
Winter		($0.62)				($1.22)		

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

AG 5C	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT) Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	413,240	$9.44	3,898,934		413,240	$11.02	4,552,006	
Part-Peak	441,692	$2.24	987,776		441,692	$2.27	1,000,828	
Maximum	588,443	$4.14	2,438,474		588,443	$3.97	2,335,533	
Winter								
Part-Peak	546,846	$0.81	441,652		546,846	$0.53	287,569	
Maximum	546,483	$2.09	1,140,177		546,483	$2.65	1,446,301	
Revenue from Demand Charges			8,907,013				9,622,237	
Revenue from Demand as % of Total			27.03%				27.74%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	34,115,305	$0.11123	3,794,601		34,115,305	$0.11241	3,834,960	
Part-Peak	35,026,612	$0.07927	2,776,416		35,026,612	$0.07650	2,679,389	
Off-Peak	140,031,788	$0.06025	8,437,052		140,031,788	$0.06311	8,837,799	
Winter								
Part-Peak	50,514,249	$0.07355	3,715,291		50,514,249	$0.06712	3,390,546	
Off-Peak	75,984,482	$0.06174	4,691,240		75,984,482	$0.06104	4,638,194	
Revenue from Energy Charges			23,414,600				23,380,887	
Revenue from Energy as % of Total			71.05%				67.40%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/day)	10,546	$54.00	569,480	1.77413	10,546	$160.00	1,687,349	5.25667
Revenue from Customer Charges			569,480				1,687,349	
Revenue from Customer Chrg as % of Total			1.73%				4.86%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/day)	10,546	$6.00	63,276	.19713	10,546	$0.00	0	.00000
Revenue from Meter Charges			63,276				0	
Revenue from Meter Chrg as % of Total			0.19%				0.00%	
			32,883,805	Total Rev			34,620,316	Total Rev
							5.28%	Ave Rate % Chg
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	34,154	($1.92)	(65,589)		34,154	($1.71)	(58,290)	
Winter	48,263	($0.05)	(2,320)		48,263	($0.15)	(7,451)	
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	402	($5.57)	(2,237)		402	($9.66)	(3,879)	
Winter	280	($1.49)	(417)		280	($1.92)	(537)	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEB. 9 SETTLEMENT)				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
E-37	Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	4,905,455	$3.37	16,523,530		4,905,455	$6.61	32,449,109	
Maximum	5,613,283	$10.18	57,155,507		5,613,283	$9.81	55,065,590	
Winter								
Maximum	4,852,540	$8.42	40,863,230		4,852,540	$3.58	17,361,565	
			114,542,268				104,876,264	
			33.56%				29.39%	
ENERGY CHARGE ($/kW)								
Summer								
Peak	395,895,241	$0.16412	64,973,214		395,895,241	$0.15328	60,680,862	
Off-Peak	1,744,861,069	$0.05544	96,734,557		1,744,861,069	$0.06440	112,369,394	
Winter								
Part-Peak	457,443,207	$0.06152	28,143,909		457,443,207	$0.07968	36,450,956	
Off-Peak	657,560,564	$0.05138	33,783,626		657,560,564	$0.05806	38,178,326	
			223,635,307				247,679,537	
			65.53%	($/meter/day)			69.42%	($/meter/day)
CUSTOMER CHARGE ($/meter/day)	141,280	$16.00	2,260,487	.52567	141,280	$30.00	4,238,412	.98563
			2,260,487				4,238,412	
			0.66%				1.19%	
METER CHARGE ($/meter/day)				($/meter/day)				($/meter/day)
Rate X	141,280	$6.00	847,682	.19713	141,280	$0.00	0	.00000
			847,682				0	
			0.25%				0.00%	
			334,034,678	Total Rev			351,581,642	Total Rev
							5.25%	Change
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	609,988	($1.46)	(892,319)		609,988	($1.18)	(721,808)	
Winter	498,602	($1.24)	(619,013)		498,602	($0.13)	(66,903)	
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	450,352	($7.55)	(3,398,002)		450,352	($7.24)	(3,258,805)	
Winter	377,244	($6.21)	(2,341,732)		377,244	($3.09)	(1,165,054)	

ILLUSTRATIVE FUNCTIONAL RATES FOR AG SETTLEMENT - Exhibit B

	Distr	Gen	PPP	Other	Total
AG 1A					
DEMAND CHARGE ($/hp of connected load)					
Summer	3.72	1.02	.00	.00	4.74
Winter	.88	.00	.00	.00	.88
ENERGY CHARGE					
Summer	.07228	.08706	.01538	.01490	.18962
Winter	.04819	.07040	.01538	.01490	.14887
CUSTOMER CHARGE ($/meter/day)	.47310	.00000	.00000	.00000	.47310

	Distr	Gen	PPP	Other	Total
AG RA					
DEMAND CHARGE ($/hp of connected load)					
Summer	3.32	1.09	.00	.00	4.42
Winter	.67	.00	.00	.00	.67
ENERGY CHARGE ($/kW)					
Summer					
Peak	.12287	.21900	.01211	.01490	.36888
Off-Peak	.04096	.05807	.01211	.01490	.12604
Winter					
Part-Peak	.03893	.06380	.01211	.01490	.12974
Off-Peak	.02596	.05490	.01211	.01490	.10786
CUSTOMER CHARGE ($/meter/day)	.47310	.00000	.00000	.00000	.47310
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000

	Distr	Gen	PPP	Other	Total
AG VA					
DEMAND CHARGE ($/hp of connected load)					
Summer	3.31	1.13	.00	.00	4.44
Winter	.71	.00	.00	.00	.71
ENERGY CHARGE ($/kW)					
Summer					
Peak	.11648	.19785	.01221	.01490	.34144
Off-Peak	.03883	.05746	.01221	.01490	.12339
Winter					
Part-Peak	.03862	.06435	.01221	.01490	.13008
Off-Peak	.02575	.05537	.01221	.01490	.10823
CUSTOMER CHARGE ($/meter/day)	.47310	.00000	.00000	.00000	.47310
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000

	Distr	Gen	PPP	Other	Total
AG 4A					
DEMAND CHARGE ($/hp of connected load)					
Summer	3.29	1.13	.00	.00	4.42
Winter	.62	.00	.00	.00	.62
ENERGY CHARGE ($/kW)					
Summer					
Peak	.11005	.13762	.01201	.01490	.27459
Off-Peak	.03668	.06163	.01201	.01490	.12522
Winter					
Part-Peak	.03790	.06509	.01201	.01490	.12990
Off-Peak	.02527	.05601	.01201	.01490	.10818
CUSTOMER CHARGE ($/meter/day)	.47310	.00000	.00000	.00000	.47310
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000

	Distr	Gen	PPP	Other	Total
AG 5A					
DEMAND CHARGE ($/hp)					
Summer	4.46	2.99	.00	.00	7.45
Winter	1.25	.00	.00	.00	1.25
ENERGY CHARGE ($/kW)					
Summer					
Peak	.06069	.12989	.01069	.01490	.21617
Off-Peak	.02023	.06600	.01069	.01490	.11182
Winter					
Part-Peak	.02285	.06896	.01069	.01490	.11740
Off-Peak	.01523	.05933	.01069	.01490	.10016
CUSTOMER CHARGE ($/meter/day)	.47310	.00000	.00000	.00000	.47310
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000

ILLUSTRATIVE FUNCTIONAL RATES FOR AG SETTLEMENT - Exhibit B

	Distr	Gen	PPP	Other	Total
AG 1B					
DEMAND CHARGE ($/kW)					
Summer	5.71	1.58	.00	.00	7.28
Winter	1.43	.00	.00	.00	1.43
ENERGY CHARGE					
Summer	.05014	.08916	.01245	.01490	.16665
Winter	.03343	.07013	.01245	.01490	.13090
CUSTOMER CHARGE ($/meter/day)	.63080	.00000	.00000	.00000	.63080
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.29)	(.56)	.00	.00	(.85)
Winter	(.20)	.00	.00	.00	(.20)

	Distr	Gen	PPP	Other	Total
AG RB					
DEMAND CHARGE ($/kW)					
Summer					
Peak	.91	1.59	.00	.00	2.50
Maximum	4.55	1.55	.00	.00	6.10
Winter					
Maximum	1.17	.00	.00	.00	1.17
ENERGY CHARGE ($/kW)					
Summer					
Peak	.09137	.22516	.01157	.01490	.34300
Off-Peak	.03046	.06494	.01157	.01490	.12187
Winter					
Part-Peak	.02792	.05979	.01157	.01490	.11417
Off-Peak	.01861	.05144	.01157	.01490	.09652
CUSTOMER CHARGE ($/meter/day)	.63080	.00000	.00000	.00000	.63080
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.20)	(.36)	.00	.00	(.57)
Winter	(.19)	.00	.00	.00	(.19)

	Distr	Gen	PPP	Other	Total
AG VB					
DEMAND CHARGE ($/kW)					
Summer					
Peak	.84	1.66	.00	.00	2.50
Maximum	4.69	1.41	.00	.00	6.09
Winter					
Maximum	1.16	.00	.00	.00	1.16
ENERGY CHARGE ($/kW)					
Summer					
Peak	.09094	.19477	.01134	.01490	.31194
Off-Peak	.03031	.06117	.01134	.01490	.11772
Winter					
Part-Peak	.02781	.05800	.01134	.01490	.11204
Off-Peak	.01854	.04991	.01134	.01490	.09468
CUSTOMER CHARGE ($/meter/day)	.63080	.00000	.00000	.00000	.63080
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.22)	(.38)	.00	.00	(.59)
Winter	(.18)	.00	.00	.00	(.18)

	Distr	Gen	PPP	Other	Total
AG 4B					
DEMAND CHARGE ($/hp of connected load)					
Summer					
Peak	1.48	1.84	.00	.00	3.32
Maximum	4.08	1.80	.00	.00	5.88
Winter					
Maximum	1.26	.00	.00	.00	1.26
ENERGY CHARGE ($/kW)					
Summer					
Peak	.06946	.09914	.01095	.01490	.19445
Off-Peak	.02315	.05899	.01095	.01490	.10799
Winter					
Part-Peak	.02434	.05759	.01095	.01490	.10778
Off-Peak	.01623	.04956	.01095	.01490	.09163
CUSTOMER CHARGE ($/meter/day)	.63080	.00000	.00000	.00000	.63080
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.26)	(.42)	.00	.00	(.67)
Winter	(.20)	.00	.00	.00	(.20)

ILLUSTRATIVE FUNCTIONAL RATES FOR AG SETTLEMENT - Exhibit B

	Distr	Gen	PPP	Other	Total
AG 5B					
DEMAND CHARGE ($/kW)					
Summer					
Peak	2.53	4.08	.00	.00	6.61
Maximum	6.47	3.34	.00	.00	9.81
Winter					
Maximum	3.58	.00	.00	.00	3.58
ENERGY CHARGE ($/kW)					
Summer					
Peak	.01758	.11200	.00879	.01490	.15328
Off-Peak	.00000	.04071	.00879	.01490	.06440
Winter					
Part-Peak	.00000	.05599	.00879	.01490	.07968
Off-Peak	.00000	.03437	.00879	.01490	.05806
CUSTOMER CHARGE ($/meter/day)	.98563	.00000	.00000	.00000	.98563
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Primary					
Summer	(.18)	(1.01)	.00	.00	(1.18)
Winter	(.13)	.00	.00	.00	(.13)
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(5.38)	(1.85)	.00	.00	(7.24)
Winter	(3.09)	.00	.00	.00	(3.09)

	Distr	Gen	PPP	Other	Total
AG 4C					
DEMAND CHARGE ($/kW)					
Summer					
Peak	3.39	4.30	.00	.00	7.69
Part-Peak	.73	.74	.00	.00	1.46
Maximum	2.75	.00	.00	.00	2.75
Winter					
Part-Peak	.29	.00	.00	.00	.29
Maximum	1.32	.00	.00	.00	1.32
ENERGY CHARGE ($/kW)					
Summer					
Peak	.03927	.11288	.01086	.01490	.17791
Part Peak	.01571	.06545	.01086	.01490	.10692
Off-Peak	.00785	.04823	.01086	.01490	.08184
Winter					
Part-Peak	.01093	.05311	.01086	.01490	.08979
Off-Peak	.00728	.04570	.01086	.01490	.07874
CUSTOMER CHARGE ($/meter/day)	2.12895	.00000	.00000	.00000	2.12895
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.18)	(.71)	.00	.00	(.89)
Winter	(.17)	.00	.00	.00	(.17)
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(3.52)	(1.34)	.00	.00	(4.86)
Winter	(1.22)	.00	.00	.00	(1.22)

	Distr	Gen	PPP	Other	Total
AG 5C					
DEMAND CHARGE ($/kW)					
Summer					
Peak	3.72	7.30	.00	.00	11.02
Part-Peak	.89	1.38	.00	.00	2.27
Maximum	3.97	.00	.00	.00	3.97
Winter					
Part-Peak	.53	.00	.00	.00	.53
Maximum	2.65	.00	.00	.00	2.65
ENERGY CHARGE ($/kW)					
Summer					
Peak	.00000	.08886	.00866	.01490	.11241
Part-Peak	.00000	.05294	.00866	.01490	.07650
Off-Peak	.00000	.03956	.00866	.01490	.06311
Winter					
Part-Peak	.00000	.04357	.00866	.01490	.06712
Off-Peak	.00000	.03749	.00866	.01490	.06104
CUSTOMER CHARGE ($/meter/day)	5.25667	.00000	.00000	.00000	5.25667
METER CHARGE ($/meter/day)	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.21)	(1.50)	.00	.00	(1.71)
Winter	(.15)	.00	.00	.00	(.15)
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(6.89)	(2.77)	.00	.00	(9.66)
Winter	(1.92)	.00	.00	.00	(1.92)

ILLUSTRATIVE FUNCTIONAL RATES FOR AG SETTLEMENT - Exhibit B

	Distr	Gen	PPP	Other	Total
E-37					
DEMAND CHARGE ($/kW)					
Summer					
Peak	2.53	4.08	.00	.00	6.61
Maximum	6.47	3.34	.00	.00	9.81
Winter					
Maximum	3.58	.00	.00	.00	3.58
ENERGY CHARGE ($/kW)					
Summer					
Peak	.01758	.11200	.00879	.01490	.15328
Off-Peak	.00000	.04071	.00879	.01490	.06440
Winter					
Part-Peak	.00000	.05599	.00879	.01490	.07968
Off-Peak	.00000	.03437	.00879	.01490	.05806
CUSTOMER CHARGE ($/meter/day)	.98563	.00000	.00000	.00000	.98563
METER CHARGE ($/meter/day)					
Rate W	.00000	.00000	.00000	.00000	.00000
Rate X	.00000	.00000	.00000	.00000	.00000
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.18)	(1.01)	.00	.00	(1.18)
Winter	(.13)	.00	.00	.00	(.13)
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(5.38)	(1.85)	.00	.00	(7.24)
Winter	(3.09)	.00	.00	.00	(3.09)

(END OF APPENDIX F)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON SMALL LIGHT AND POWER RATE DESIGN ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Small Light and Power Rate Design Settlement Agreement (Settling Parties, SLP Settlement) agree on a mutually acceptable outcome to the SLP rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This SLP Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses SLP rate issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this SLP Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this SLP Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- California City-County Street Light Association
- California Solar Energy Industries Association (CAL SEIA)
- Division of Ratepayer Advocates (DRA)
- Pacific Gas and Electric Company (PG&E)
- PV Now (PV Now)
- The Utility Reform Network (TURN)
- Vote Solar

III. SETTLEMENT CONDITIONS

This SLP Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on SLP rate design, subject to the conditions set forth below:

1. This SLP Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This SLP Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.
2. This SLP Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This SLP Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this SLP Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this SLP Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
5. This SLP Settlement may be amended or changed only by a written agreement signed by the Settling Parties.
6. The Settling Parties shall jointly request Commission approval of this SLP Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the SLP Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the SLP rate design agreed to herein. In the event the Commission rejects or modifies this SLP Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF,

CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, the Settling Parties to this SLP Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. SLP SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the rate design for the SLP class embodied in this

SLP Settlement takes the revenue allocation reached for that class in the February 9 Settlement and ensures that it is fully recovered through SLP rates in a manner that is just and reasonable, in the public interest, and that reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which is based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this SLP Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the SLP class and will differ from the rates presented herein. However, these actual rates shall be based on the SLP rate structure described below. The SLP class consists of Schedules A-1, A-6, A-15 and TC-1. Illustrative allocation to these schedules is set forth in Exhibit A and Illustrative rates are set forth in Exhibit B to this SLP Settlement.

The Settling Parties agree that all testimony served prior to the date of this SLP Settlement that addresses the issues resolved by this SLP Settlement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree that this SLP Settlement resolves all SLP rate design issues in A.06-03-005.

VI. SLP RATE DESIGN SETTLEMENT TERMS

A. Illustrative revenues and average settlement rates for the SLP rate schedules after revenue allocation and rate design are presented in Exhibit A. The allocations and average rates were developed to collect the revenue allocated to the SLP customer classes set forth in Tables 5-A and 5-B of the February 9 Settlement based on estimated March 2007 revenue requirements. Adopted revenue requirements in effect upon settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual average rates and allocated revenues may vary from those shown in Exhibit A when the Phase 2 rate changes are implemented.

B. The Settling Parties agree to establish revenue neutrality between Schedules A-1 and A-6 in two steps. First, upon settlement implementation, Schedule A-6 will move approximately two-thirds of the way toward full revenue neutrality with Schedule A-1. This step will be accomplished by capturing in Schedules A-1 and A-6 an amount equal to the termination of the Fixed Transition Amount (Trust Transfer Amount) rate component, which is expected to end December 31, 2007. If the settlement is implemented prior to January 1, 2008, the Schedule A-1 and A-6 rates will be set to achieve two-thirds movement toward revenue neutrality assuming termination of the FTA on January 1, 2008. The second step to complete the movement to full revenue neutrality will occur on January 1, 2010. In the interim between these two steps, each electric rate change will seek to maintain the ratio of the Schedule A-1 to A-6 average rate established upon initial implementation of the settlement after termination of the FTA. Similarly, PG&E will seek to maintain the full revenue neutral ratio of the Schedule A-1 to A-6 average rate established on January 1, 2010 until the next GRC Phase 2 proceeding. This term modifies and supersedes term VII. 3. (G) in the February 9 settlement, and will be implemented to the extent practicable, subject to other applicable revenue allocation or rate design constraints. Exhibits A and B are based upon implementation prior to January 1, 2008, and therefore provide illustrative results prior to elimination of the current small commercial FTA rate of $0.00661 per kWh. Generally, movement toward and attainment of revenue neutrality between Schedules A-1 and A-6 will correct current inappropriate rate relationships whereby customers can automatically realize significant bill savings simply by switching from Schedule A-1 to

Schedule A-6 despite having poor time-of-use load profiles.

C. The Settling Parties agree that the basic rate designs for each of the applicable SLP rate schedules will be updated upon settlement implementation using the methods underlying development of the illustrative settlement rates for Schedules A-1, A-6, A-15, and TC-1 presented in Exhibit B. These methods reflect approaches proposed by PG&E in its Rate Update testimony, Exhibit (PG&E-4), filed June 26, 2006, as updated to incorporate the revenue allocation proposals and updated marginal costs agreed upon in the February 9 Settlement, and other revenue allocation or rate design revisions discussed herein.

D. The Settling Parties agree to a pilot program that increases the maximum demand limit for Schedule A-6 customers that install a solar photovoltaic system from 500 kilowatts to 1,000 kilowatts. However, in light of the fact that extension of net energy metering to larger customers, and specifically under the provisions of Schedule A-6, will increase the degree of cost shifting to other customers, this provision will be limited to no more than a cumulative 20 megawatts (MW) of installed solar system output, as identified in the Pacific Gas and Electric Company Permission to Operate letter to Net Energy Metering customers. The change would allow a customer whose maximum billing demand has been between 499 and 999 kilowatts for at least three consecutive months during the most recent 12-month period, or that otherwise is currently taking service, or would be required to take service, on Schedule E-19 on a mandatory basis, and that installs a solar photovoltaic system that meets at least 20 percent of the measured maximum demand, to voluntarily move to the Schedule A-6 tariff. Such customers will be eligible to take net energy metering service under

Schedule NEM, subject to the terms and conditions therein. The maximum demand measurement would be based on facility load before the installation of any solar system. This expansion of Schedule A-6 eligibility to 999 kW shall apply to solar customers only. For net energy metering customers currently taking service on a mandatory basis on Schedule E-19 as of the date of settlement implementation, PG&E shall provide a one-time option during the first 90 days after the effective date of implementation of this settlement for these customers to migrate to net energy metering service on Schedule A-6. Any such existing net energy metering Schedule E-19 customers' solar system size transferring to Schedule A-6 shall count toward the 20 MW pilot program cap. Appropriate tariff revisions shall be made to the applicability sections of Schedule A-6 and E-19.

E. The Settling Parties agree that the increases to SLP fixed monthly customer charges reflected in Exhibit B are reasonable. The Settling Parties agree further that at such time as the customer's existing TOU meter is replaced as part of the Advanced Meter Infrastructure (AMI) Project, pursuant to D.06-07-027, and the new meter is activated and used for billing, the current ongoing monthly TOU meter charges applicable to customers taking voluntary TOU service under Schedule A-6 will cease.

F. The calculation of the CARE discount for commercial CARE customers under Schedule E-CARE shall be based on a rate per kWh discount, rather than the currently effective methodology tied to a percentage discount, surcharges, and prior June 10, 1996 rates. The new method will improve customer understanding, simplify billing, avoid calculation of a bundled bill for direct access commercial CARE customers, and maintain parity between residential and commercial CARE average discount percentages. The commercial CARE discount per kWh on each rate schedule shall be pegged to the overall percentage distribution and generation discount for the residential CARE customer class, and assigned to the commercial distribution rate component, with the additional waiver of the Department of Water Resources Bond charge, and the CARE Surcharge portion of the Public Purpose Program rate component otherwise applicable to each commercial rate schedule. The commercial CARE rate per kWh discount shall be listed in Schedule E-CARE, and will vary by rate schedule. These Schedule E-CARE rates will be updated with each future electric rate change. Should commercial CARE customers take service on a rate not listed in Schedule E-CARE, PG&E shall use the most appropriate rate schedule currently listed, until such time as a new corresponding rate per kWh discount is developed and available for billing purposes.

G. The special facility charge related to direct current electrical service on Schedule A-15 shall increase from $15 to $20 per month.

H. PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15 and 1-16, shall be adopted for Direct Access and Community Choice Aggregation service.

I. The Settling Parties agree that the revised Schedule A-6 fulfills the requirements of Senate Bill (SB) 1, Public Utilities Code Section 2851 (a)(4), requiring "a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems…" This Settlement does not restrict parties from taking positions they deem appropriate in a subsequent proceeding that addresses time-variant rates, provided that prior to the next GRC Phase 2 proceeding, no Settling Party may argue that Schedule A-6 does not meet the SB-1 requirement for "a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems."

J. The illustrative rates shown in Exhibit B are developed to collect the same revenue allocated to the SLP class that was used for the February 9 Settlement. The actual rates developed to implement this decision will vary based on the then current adopted revenue requirements.

K. Timing of Rate Changes: Certain elements of this SLP Settlement require employee training and/or changes to PG&E systems beyond a normal change to a rate value. These changes may include revision for expanded Schedule A-6 solar eligibility in item D, elimination of the ongoing TOU meter charge in item E, revision to the commercial CARE bill calculation in item F, and revision of the franchise fee surcharge calculation in item H. These systems and program changes will be implemented by PG&E diligently as time permits and in a manner consistent with maintaining the secure, smooth operations of the systems involved. The Settling Parties recognize that some initiatives could take several months to implement.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this SLP Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This SLP Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the SLP Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this SLP Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California City-County Street Light Association

By: /s/
Reed V. Schmidt

Title: Energy Economist

Date: April 27, 2007

California Solar Energy Industries Association

By: /s/

Title: Executive Director

Date: April 27, 2007

Division of Ratepayer Advocates

By: /s/

Title: Director

Date: 4/27/07

Pacific Gas and Electric Company

By: /s/
Dan Pease

Title: Manager, Electric Rates

Date: April 27, 2007

PV Now

By: /s/
Joseph F. Wiedman

Title: Attorney for PV Now

Date: April 27, 2007

The Utility Reform Network

By: /s/
Matthew Freedman

Title: Staff Attorney

Date: April 27, 2007

Vote Solar

By: /s/

Title: Program Director

Date: 4/26/07

Small Light and Power Rate Design Settlement

Exhibit A

Small Light and Power Bundled Intra Class Revenue Allocation

Schedule	Estimated 3/1/07 Revenue	Estimated 3/1/07 Avg Rate	Illustrative Revenue	Illustrative Avg Rate	Percent Change
A-1	$979,441,330	$0.16717	$1,007,689,195	$0.17199	2.9%
A-6	$341,872,938	$0.13782	$388,557,101	$0.15664	13.7%
A-15	$359,168	$0.33928	$413,249	$0.39037	15.1%
TC-1	$6,337,827	$0.17644	$5,528,655	$0.15391	-12.8%
Total	$1,328,011,263	$0.15854	$1,402,188,199	$0.16739	5.6%

Small Light and Power Rate Design Settlement

Exhibit B

Illustrative Small Light and Power Rate Design

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR SLP RATE DESIGN SETTLEMENT			
A-1							
Bundled							
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
ENERGY CHARGES ($/kWh)							
Summer	3,037,697,559	$0.18329	$556,794,259	3,037,697,559	$0.18868	$573,155,520	
Winter	2,821,321,264	$0.13331	$376,123,169	2,821,321,264	$0.13555	$382,418,303	
Revenue from Energy Charges			$932,917,428			$955,573,823	
Revenue from Energy as % of Total			95.19%			94.78%	
CUSTOMER CHARGE ($/meter/mo.)							
Singlephase	2,893,286	$8.10	$23,435,617	2,893,286	$9.00	$26,039,575	
Polyphase	1,972,871	$12.00	$23,674,447	1,972,871	$13.50	$26,633,753	
Revenue from Customer Charges			$47,110,064			$52,673,327	
Revenue from Customer Chrg as % of Total			4.81%			5.22%	
Total	5,859,018,823		$980,027,492	5,859,018,823		$1,008,247,150	Total Rev
						2.88%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR SLP RATE DESIGN SETTLEMENT			
A-6							
Bundled							
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
ENERGY CHARGES ($/kWh)							
Summer							
Peak	257,489,677	$0.31884	$82,098,909	257,489,677	$0.37388	$96,269,296	
Partial-Peak	323,024,447	$0.15659	$50,582,440	323,024,447	$0.17800	$57,499,929	
Off-Peak	792,028,336	$0.09292	$73,595,852	792,028,336	$0.11587	$91,772,381	
Winter							
Partial-Peak	468,559,417	$0.13797	$64,646,511	468,559,417	$0.13899	$65,122,974	
Off-Peak	639,489,747	$0.10178	$65,088,814	639,489,747	$0.11537	$73,778,411	
Revenue from Energy Charges			$336,012,526			$384,442,992	
Revenue from Energy as % of Total			98.27%			98.93%	
CUSTOMER CHARGE ($/meter/mo.)							
Singlephase	149,326	$8.10	$1,209,543	149,326	$9.00	$1,343,936	
Polyphase	208,748	$12.00	$2,504,975	208,748	$13.50	$2,818,097	
Revenue from Customer Charges			$3,714,518			$4,162,034	
Revenue from Customer Chrg as % of Total			1.09%			1.07%	
METER CHARGE ($/meter/mo.)							
A-6	358,074	$6.12	$2,191,414	358,074	NA		
Revenue from Meter Charge			$2,191,414			$0	
Revenue from Meter Chrg as % of Total			0.64%			0.00%	
Total							
	2,480,591,624		$341,918,458	2,480,591,624		$388,605,025	Total Rev
						13.65%	Change

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR SLP RATE DESIGN SETTLEMENT			
A-15							
Bundled							
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
ENERGY CHARGES ($/kWh)							
Summer	529,328	$0.17916	$94,837	529,328	$0.18455	$97,688	
Winter	529,283	$0.12918	$68,375	529,283	$0.13142	$69,556	
Revenue from Energy Charges			$163,212			$167,244	
Revenue from Energy as % of Total			45.44%			40.47%	
CUSTOMER CHARGE ($/meter/mo.)							
A-15	8,483	$8.10	$68,712	8,483	$9.00	$76,346	
Revenue from Customer Charges			$68,712			$76,346	
Revenue from Customer Chrg as % of Total			19.13%			18.47%	
FACILITIES CHARGE ($/meter/mo.)							
A-15	8,483	$15.00	$127,244	8,483	$20.00	$169,659	
Revenue from Facilities Charges			$127,244			$169,659	
Revenue from Facility Chrg as % of Total			35.43%			41.05%	
Total	1,058,611		$359,168	1,058,611		$413,249	Total Rev
						15.06%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes - Exhibit B

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR SLP RATE DESIGN SETTLEMENT			
TC-1							
Bundled	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
ENERGY CHARGES ($/kWh)							
Summer	17,936,845	$0.14703	$2,637,182	17,936,845	$0.12123	$2,174,517	
Winter	17,984,426	$0.14703	$2,644,178	17,984,426	$0.12123	$2,180,286	
Revenue from Energy Charges			$5,281,361			$4,354,803	
Revenue from Energy as % of Total			83.33%			78.77%	
CUSTOMER CHARGE ($/meter/mo.)							
TC-1	130,428	$8.10	$1,056,467	130,428	$9.00	$1,173,852	
Revenue from Customer Charge			$1,056,467			$1,173,852	
Revenue from Customer Chrg as % of Total			16.67%			21.23%	
Total	35,921,271		$6,337,827	35,921,271		$5,528,655	Total Rev
						-12.77%	Change

ILLUSTRATIVE FUNCTIONAL RATES FOR SLP SETTLEMENT

A-1

BUNDLED	Dist	Gen	PPP	Other	Total
ENERGY CHARGES ($/kWh)					
Summer					
Total	$0.05735	$0.09868	$0.01133	$0.02132	$0.18868
Winter	$0.03823	$0.06466	$0.01133	$0.02132	$0.13555
Total					
CUSTOMER CHARGES ($/mtr/day)					
Singlephase	$0.29569				$0.29569
Polyphase	$0.44353				$0.44353

A-6

BUNDLED	Dist	Gen	PPP	Other	Total
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.13487	$0.20781	$0.00987	$0.02132	$0.37388
Part-Peak	$0.05395	$0.09286	$0.00987	$0.02132	$0.17800
Off-Peak	$0.02697	$0.05770	$0.00987	$0.02132	$0.11587
Winter					
Part-Peak	$0.04424	$0.06355	$0.00987	$0.02132	$0.13899
Off-Peak	$0.02950	$0.05468	$0.00987	$0.02132	$0.11537
CUSTOMER CHARGES ($/mtr/day)					
Singlephase	$0.29569				$0.29569
Polyphase	$0.44353				$0.44353

A-15

BUNDLED	Dist	Gen	PPP	Other	Total
ENERGY CHARGES ($/kWh)					
Summer					
Total	$0.05735	$0.09868	$0.01133	$0.01719	$0.18455
Winter					
Total	$0.03823	$0.06466	$0.01133	$0.01719	$0.13142
CUSTOMER CHARGE ($/mtr/day)	$0.29569				$0.29569
FACILITIES CHARGE ($/mtr/day)	$0.65708				$0.65708

TC-1

BUNDLED	Dist	Gen	PPP	Other	Total
ENERGY CHARGES ($/kWh)					
Summer					
Total	$0.03153	$0.06653	$0.00598	$0.01719	$0.12123
Winter					
Total	$0.03153	$0.06653	$0.00598	$0.01719	$0.12123
CUSTOMER CHARGE ($/mtr/day)	$0.29569				$0.29569

ILLUSTRATIVE FUNCTIONAL RATES FOR SLP SETTLEMENT

E-CARE Discounts ($/kWh)

	Dist	PPP	DWR Bond	Total
A-1	$0.06462	$0.00487	$0.00469	$0.07417
A-6	$0.05885	$0.00487	$0.00469	$0.06841
A-10S	$0.05217	$0.00487	$0.00469	$0.06173
A-15	$0.06462	$0.00487	$0.00469	$0.07417
E-19VS	$0.04322	$0.00487	$0.00469	$0.05278

(END OF APPENDIX G)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON COMMERICAL BUILDING MASTER METER ISSUES IN PG&E'S APPLICATION 06-03-005

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Commercial Building Master Meter Settlement Agreement (Settling Parties, Master Meter Settlement) agree on a mutually acceptable outcome to the commercial building master meter issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. The details of this Master Meter Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- Building Owners and Managers Associations of San Francisco and of California (BOMA)
- Pacific Gas and Electric Company (PG&E)

III. SETTLEMENT CONDITIONS

This Master Meter Settlement resolves the issues raised by the Settling Parties in A.06-03-005 involving commercial building master meters, subject to the conditions set forth below:

1. This Master Meter Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.

2. This Master Meter Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Master Meter Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

3. The Settling Parties agree that this Master Meter Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

4. The Settling Parties agree that no provision of this Master Meter Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.

5. This Master Meter Settlement may be amended or changed only by a written agreement signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this Master Meter Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. In the event the Commission rejects or modifies this Master Meter Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On

November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, the Settling Parties to this Master Meter Settlement reached an agreement in principle.

V. MASTER METER SETTLEMENT TERMS GENERALLY

1. The Settling Parties agree that the terms embodied in this Master Meter Settlement are just and reasonable, in the public interest, and reflect a reasonable compromise of Settling Parties' proposals.

2. The Settling Parties agree that all testimony served prior to the date of this Master Meter Settlement that addresses the issues resolved by this Master Meter

Settlement should be admitted into evidence without cross-examination by the Settling Parties.

3. The Settling Parties further agree that this Master Meter Settlement resolves all commercial building master meter issues in A.06-03-005, except as otherwise expressly set forth.

VI. MASTER METER SETTLEMENT TERMS

1. PG&E and BOMA agree that it is in the public interest that commercial building tenants receive price signals and have the opportunity to participate in dynamic pricing and energy conservation programs.

2. PG&E and BOMA agree that it is in the public interest that building owners participate in dynamic pricing and energy conservation programs, and BOMA will encourage its membership to do so, and to timely pass on to commercial tenants dynamic pricing and energy conservation options or incentives that may become available.

3. PG&E and BOMA agree that they may participate in any Commission proceedings that address how dynamic pricing and energy conservation programs may be made available to commercial building tenants. This Master Meter Settlement does not restrict parties from taking positions they deem appropriate in any proceeding that addresses such issues.

4. PG&E and BOMA agree that the revisions to the applicable sections of PG&E Electric Rules 1 and 18, attached to this Master Meter Settlement as Exhibits A and B, advance the goals set forth above and should be adopted.

5. The parties do not intend this Master Meter Settlement to be precedential regarding any principle or issue in this proceeding or in any future proceeding and they represent that it shall have no application to PG&E customers other than commercial building owners, as defined in PG&E Electric Rule 1, and shall be applicable only to commercial tenants of such building owners.

6. Nothing in this Master Meter Settlement is intended to create or constitute evidence of a wholesale relationship between PG&E and commercial building owners. The parties represent that the relationship between PG&E and commercial building owners is and will remain a retail relationship, and that nothing in this Master Meter Settlement creates or is evidence of a commercial relationship between PG&E and sub-metered tenants in commercial buildings.

7. Nothing in this Master Meter Settlement is intended to create or constitute evidence of a utility relationship between commercial building owners and their sub-metered tenants, and the parties represent and understand that commercial building owners who sub-meter tenants do not and will not thereby become utilities.

8. PG&E and BOMA understand and represent that the issuance of energy statements by commercial building owners to their sub-metered tenants will not constitute evidence that a building owner is a utility or that the building owner's relationship with PG&E is anything other than retail.

9. PG&E and BOMA agree that the cost of electricity allocated to commercial building tenants will be billed at the same rate as the master meter billed by PG&E. Nothing in this Master Meter Settlement allows the master meter owner to "re-sell" electricity. Nothing in this Master Meter Settlement prevents building owners from

separately charging tenants for submetering and energy information services, including the amortized cost of re-wiring, meter and data server hardware and software costs, and ongoing meter and meter data systems operations, maintenance, and administrative costs, according to terms jointly agreed to by tenants and owners and specified in leases.

10. PG&E and BOMA agree that implementation of this Master Meter Settlement will be on a single premise basis, i.e., a master meter may connect to sub-meters in only one building.

11. PG&E and BOMA agree that all attachments and devices on the customer's side of the master meter used for the purposes stated herein to measure tenant electricity use for the purposes of taking advantage of dynamic pricing and energy conservation opportunities shall conform to all safety rules, regulations, and general orders established by the State of California and its subdivisions and local governments and their subdivisions. PG&E and BOMA agree that all sub-meters installed by a commercial building owner will be selected, installed and tested in accordance with Title 4 of the California Code of Regulations. PG&E shall have no liability with respect to equipment installed on the customer's side of the meter pursuant to this Master Meter Settlement.

VII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Master Meter Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the Master Meter Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Master Meter Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Building Owners and Managers Association

By: /s/
Bill F. Roberts

Title: President, Economic Sciences Corp.
For BOMA

Date: 4/26/2007

Pacific Gas and Electric Company

By: /s/
Dan Pease

Title: Manager, Electric Rates

Date: 4/27/2007

Exhibit A

Rule 1

RULE 1—DEFINITIONS
(Continued)

ELECTRONIC BILLING: A billing method whereby at the mutual option of the Customer and PG&E, the Customer elects to receive, view, and pay bills electronically and to no longer receive paper bills. (L)

ELECTRONIC PRESENTMENT: When made available or transmitted electronically to the Customer at an agreed upon location.

ENERGY SUPPLY OR PROCUREMENT SERVICES: Includes, but is not limited to, procurement of electric energy; all scheduling, settlement, and other interactions with Scheduling Coordinators, and the ISO; all ancillary services and congestion management.

ENERGY SERVICE PROVIDER (ESP): An entity who provides electric supply services to Direct Access Customers within PG&E's service territory. An ESP may also provide certain metering and billing services to its DA Customers as provided for within these tariffs. (L)

FEDERAL ENERGY REGULATORY COMMISSION (FERC): Federal agency with jurisdictional responsibilities over electric transmission service and electric sales for resale.

FIXED TRANSITION AMOUNT (FTA) CHARGE: See Trust Transfer Amount Charge.

GENERATION CUSTOMER: Any PG&E (electric customer with electric generation facilities (including back-up generation in parallel with PG&E) on the customer's side of the interconnection point.

HIGH RISE BUILDING: A multi-story, multi-tenant building located on a single premises usually comprised of three or more stories and equipped with elevators.

HOURLY PRICING OPTION: This option is suspended

INDEPENDENT SYSTEM OPERATOR (ISO): The California Independent System Operator Corporation, a state-chartered, non-profit corporation that controls the transmission facilities of all participating transmission owners and dispatches certain generating units and loads. The ISO is responsible for the operation and control of the statewide transmission grid.

(Continued)

Exhibit B

Rule 18

RULE 18—SUPPLY TO SEPARATE PREMISES AND SUBMETERING OF ELECTRIC ENERGY

A. SEPARATE METERING

Separate premises, even though owned by the same customer, will not be supplied through the same meter, except as may be specifically provided for in the applicable rate schedule.

B. OTHER USES OR PREMISES

A customer shall not furnish or use electricity received from PG&E upon premises, or for purposes, other than those specified in his application for service.

C. FURNISHING AND METERING OF ELECTRICITY

1. RESIDENTIAL SERVICE

PG&E will furnish and meter electricity to each individual residential dwelling unit, except:

a. Where electricity is furnished under a rate schedule that specifically provides for resale service; or

b. Where a customer, or his predecessors in interest on the same premises, was a customer on June 13, 1978, receiving electricity through a single meter to an apartment house, mobile home park, or other multifamily accommodation, and the cost of electricity is absorbed in the rental for the individual dwelling unit, there is no separate identifiable charge by such customer to the tenants for electricity, and the rent does not vary with electric consumption; or

c. Where a customer or his predecessors in interest on the same premises was a customer on December 14, 1981, and submeters and furnishes electricity to residential tenants at the same rates and charges that would be applicable if the user were purchasing such electricity directly from PG&E; or

d. Where a mobile home park or manufactured housing community developer, owner or operator who installs, owns and operates the electric distribution system within the park, submeters and furnishes electricity to residential tenants in each occupancy, charges the same rates that would be applicable if the user were purchasing such electricity directly from PG&E, unless construction of a new mobilehome park, or manufactured housing community commenced after January 1, 1997. (T) (T) (T)

(Continued)

RULE 18—SUPPLY TO SEPARATE PREMISES AND SUBMETERING OF ELECTRIC ENERGY
(Continued)

C. FURNISHING AND METERING OF ELECTRICITY (Cont'd.)

1. RESIDENTIAL SERVICE (Cont'd.)

e. Nothing in this section shall prevent PG&E from furnishing separately-metered service to electric equipment used in common by residential tenants or owners. (L)
|
|
(L)

2. NONRESIDENTIAL SERVICE

PG&E will furnish and meter electricity to each individual nonresidential premises or space, except:

a. Where electricity is furnished under a rate schedule that specifically provides for resale service; or

b. Where a customer is receiving electricity through a single meter and the cost of electricity is absorbed in the rental for the individual premises or spaces, there is no separate identifiable charge by such customer to the tenants for electricity, and the rent does not vary with electric consumption; or **where all of the following conditions are met:**

1. Service is supplied to a high rise building[1] which is owned or managed by a single entity on a single premises; and

2. Where a master-meter customer installs, owns, and maintains electric submeters on its existing building's distribution system for cost allocation of dynamic pricing and/or conservation incentive purposes the cost of electricity allocated to the commercial building tenants will be billed at the same rate as the master meter billed by PG&E under the CPUC approved rate schedule servicing the master meter.

c. Where, in the sole opinion of PG&E, it is impractical for PG&E to meter individually each premises or space. In such a case, PG&E will meter those premises or spaces that it is practical to meter, if any.

d. Where the Commission has authorized PG&E to supply electric service through a single meter and to furnish service to nonresidential tenants on the same basis as in 1.c. above.

1. See Rule 1 for definition of High Rise Building.

e. Where customer was furnishing electricity on a submetered basis to tenants for nonresidential purposes on May 15, 1962, at the same rates and charges that PG&E would charge for the service if supplied by it directly and where such customer desires to continue to receive such nonresidential service. Unless otherwise ordered by the Commission in an appropriate proceeding or requested by the customer, such nonresidential service on a submetered basis, together with additions, rearrangements and changes to the service, is permitted so long as the customer's premises, as defined by Decision No. 60938, are used by the customers or his successors in interest for the same general purpose.

(Continued)

RULE 18—SUPPLY TO SEPARATE PREMISES AND SUBMETERING OF ELECTRIC ENERGY
(Continued)

C. FURNISHING AND METERING OF ELECTRICITY (Cont'd.)

3. MARINAS AND SMALL CRAFT HARBORS

Notwithstanding any other provision of this rule, PG&E will furnish electrical service to the master-meter customer at a privately or publicly owned marina or small craft harbor. The master-meter customer may submeter individual slips or berths at the marina or harbor but may (T) not submeter any land-based facility or tenant.

If the master-meter customer submeters and furnishes electricity to individual slips or berths, the rates and charges to the user must not exceed those that would apply if the user were purchasing such electricity directly from PG&E.

4. RECREATIONAL VEHICLE (RV) PARKS

PG&E will provide electric service to all spaces in an RV park through one meter unless the condition under c. below applies. PG&E will not provide individual metering to each RV space.

Under no circumstances shall an RV park owner/operator install submeters and bill the tenants for submetered energy use unless condition a., b., or c. below applies and the provisions of Section D. below are met:

a. Where the RV park owner/operator installed a submetering system prior to May 15, 1962.

b. Where the RV park owner/operator rents all of the RV spaces on a prepaid monthly basis to RV units used as permanent residences and qualifies for service under Schedule ESR.

c. Where a master-metered RV park owner/operator rents RV spaces on a prepaid monthly basis to permanent-residence RV units and on a daily/weekly basis to transient RV units and arranges the electric distribution system in accordance with PG&E's applicable tariffs so that all electricity to the permanent-residence RV spaces is supplied through a separate PG&E meter. In this situation, only the separately metered portion of the RV park where all of the spaces are rented on a prepaid monthly basis to permanent-residence RV units can be submetered and would qualify for service under Schedule ESR.

(Continued)

RULE 18—SUPPLY TO SEPARATE PREMISES AND SUBMETERING OF ELECTRIC ENERGY
(Continued)

C. FURNISHING AND METERING OF ELECTRICITY (Cont'd.)

4. RECREATIONAL VEHICLE (RV) PARKS (Cont'd.) (N)

Where the master-metered RV park owner/operator does not submeter the electric service to the RV spaces, such energy use shall be absorbed in the tenant's rental charge which cannot vary month to month.

Where the master-metered RV park owner/operator installed submeters prior to May 15, 1962 (see condition a. above), the owner/operator may bill the RV park tenants for such energy use, provided the billings are calculated using the same rate schedules PG&E uses for billing its customers.

Where the master-metered RV park owner/operator submeters the electric service to the permanent-residence RV park spaces under Schedule ESR (see conditions b. and c. above), the owner/operator will bill the prepaid monthly tenants for such energy use using the same rate schedules PG&E uses for billing its residential customers. (N)

D. TESTING OF SUBMETERS

As a condition of service for submetering, where electric energy is furnished in accordance with Paragraphs C.1., C.2., C.3, and C.4. above, customers using (T) submeters as a basis for charges for electricity shall submit to PG&E certification by a meter testing laboratory, satisfactory to PG&E, as to the accuracy of the submeters upon initial installation of such submeters, or for existing submeters upon request of PG&E. As a further condition of service for submetering, the customer shall agree that he will be governed by PG&E's Rule 17, Meter Tests and Adjustment of Bills for Meter Error, with the exception that the word "subcustomer" be substituted for "customer" and the words "Utility's customer" be substituted for "Company." As a further condition of service for submetering, the customer shall agree that PG&E may inspect and examine customer's billing procedures from time to time to determine that such service is made in accordance with this rule or as otherwise may be authorized by the Commission.

E. In the event such energy is furnished or resold otherwise than as provided for above, PG&E may either discontinue service to the customer or, where feasible, furnish electric energy directly to the subcustomer in accordance with PG&E's tariff on file with the Commission.

(END OF APPENDIX H)