

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 2007¹
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 Division³ 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.

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.

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.

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

