APPENDIX A

LIST OF APPEARANCES

APPENDIX A

List of Appearances

Applicant: Gail L. Slocum, Attorney at Law, for Pacific Gas & Electric Company.

Interested Parties: Alcantar & Kahl, LLP, by Michael Alcantar, for Cogeneration Association of California; Evelyn Kahl, Attorney at Law, for Energy Producers and Users Coalition; Nora Sheriff, Attorney at Law, for Valero Refining Company – California and Karen Terranova, for Occidental Elk Hills, Inc.; Devra Bachrach, for Natural Resources Defense Council; Barkovich and Yap, Inc., by Barbara R. Barkovich, for CLECA/Consultants; Tom Beach of Crossborder Energy, for CA Manufacturers & Technology Association; Law Office of William Booth, by William H. Booth, for California Large Energy Consumers Association; McCracken, Byers & Haesloop, by David J. Byers, Attorney at Law, for California City – County Street Light Association; Joseph Peter Como, for the City and County of San Francisco; Sheila Day, for Western Manufactured Housing Communities; Grueneich Resource Advocates, by Dian M. Grueneich and Jack P. McGowan, for University of California and California State University; Ellison, Schneider & Harris, LLP, by Lynn Haug, Attorney at Law, for East Bay Municipal Utility District and Douglas K. Kerner, Attorney at Law, for Duke Energy North America; Sutherland, Asbill & Brennan, by Keith McCrea, Attorney at Law, for CA Manufacturers & Technology Association; Karen Norene Mills, Attorney at Law, for California Farm Bureau Federation; Anderson & Poole, by Edward G. Poole, for Western Manufactured Housing Community Association; Bruce A. Reed, Attorney at Law, for Southern California Edison Company; James Ross, of RCS, Inc., for Coalinga Cogeneration Company; Goodin, MacBride, Squeri, Ritchie & Day, LLP, by James D. Squeri, for California Retailers Association; Downey, Brand, LLP, by Ann L. Trowbridge, for Distributed Generation/Distributed Energy Resources and Merced Irrigation District; Ed Yates, for California League of Food Processors; Department of the Navy, by Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Davis, Wright, Tremaine, LLP, by Jeffrey P. Gray, Attorney at Law, for BART; and Irene K. Moosen, Attorney at Law, for WMA.

Intervenors: Mike Florio and Matthew Freedman, for The Utility Reform Network; Morrison & Foerster, LLP, by Peter W. Hanschen, and Steven Moss, of M.Cubed, for Agricultural Energy Consumers Association; John R.

Redding, of Arcturus Energy Consulting; for Silicon Valley Manufacturing Group; and Scott T. Steffen, for Modesto Irrigation District.

State Service: Patrick L. Gileau, Attorney at Law, Christopher Danforth, and Dexter E. Khoury; for the Office of Ratepayer Advocates; Donald J. LaFrenz, and Maria Vanko, for the Energy Division.

(END OF APPENDIX A)

APPENDIX B

MAY 13, 2005 SETTLEMENT

SETTLEMENT IN APPLICATION 04-06-024

I. SETTLEMENT AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the parties to this Settlement (Settling Parties) agree on a mutually acceptable outcome to the issues in Application (A.) 04-06-024, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design, that are specified in this Settlement.

II. SETTLEMENT PARTIES

The Settling Parties are as follows:

Agricultural Energy Consumers Association (AECA)

Building Owners and Managers Associations of San Francisco and of California (BOMA)

California City-County Street Light Association (CAL-SLA)

California Farm Bureau Federation (CFBF)

California Large Energy Consumers Association (CLECA)

California Manufacturers & Technology Association (CMTA)

California Retailers Association (CRA)

Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC)

East Bay Municipal Utility District (EBMUD)

Energy Users Forum (EUF)

Indicated Commercial Parties (ICP)

Office of Ratepayer Advocates (ORA)

Pacific Gas and Electric Company (PG&E)

The Utility Reform Network (TURN)

Wal-Mart Stores, Inc. (Wal-Mart)

The Western Manufactured Housing Communities Association (WMA)

III. SETTLEMENT CONDITIONS

The Settling Parties agree this Settlement resolves the specified issues raised in A.04-06-024 by the Settling Parties, subject to the following reservations:

1. This 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 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 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 Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest, in accordance with Rule 51.1(e).

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

5. This 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 Settlement and shall actively support prompt approval of the Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement, the Settling Parties reserve their rights under Rule 51.7.

IV. SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

> On August 27, 2004, the *Scoping Memo And Ruling of Assigned Commissioner* (ACR) stated: "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding). …

The three general subjects of the application are marginal costs, revenue allocation and rate design." The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 10, 2005, parties to the settlement discussions reached agreement in principle on the terms of this Settlement, and counsel for PG&E notified Administrative Law Judge (ALJ) Mattson that most of the active major parties had reached an agreement in principle regarding marginal cost and revenue allocation issues and certain rate design issues and that they would continue their efforts to reach agreement on additional issues.

V. SETTLEMENT TERMS

1. 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 customer class and function and on that cost basis to set the allocation of revenue among customer classes and functions. While the Settling Parties disagree on particular marginal costs and the magnitude of changes in revenue allocation that would be necessary to bring customer classes and functions to their full cost of service, all the Settling Parties agree generally that the residential customer class is bearing less than its full cost of service and most non-residential customer classes are bearing more than their full cost of service. To better align rates with their cost of service, the Settling Parties agree to the revenue allocation set forth in this Settlement without agreeing on particular marginal costs or costs of service. The revenue allocation procedures agreed to in this Settlement better align customer class average rates with customer class costs of service over time by allocating certain future revenue requirement decreases, to the extent they occur, only to non-residential customer classes.

No later than May 20, 2005, PG&E and ORA will serve a comparison exhibit showing the impact of the Settlement in relation to the litigation positions of PG&E and ORA, as required by Rule 51.1(c).

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

The Settling Parties further agree that this Settlement will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.04-06-024. 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.

In terms of the 36 specific issues identified in Attachment A to the ACR and in subsequent ALJ rulings (Marginal Cost issues 1.1-1.13, Revenue Allocation issues 2.1-2.7, and Rate Design issues 3.1-3.16), only the following 14 issues will remain to be addressed in A.04-06-024 if this Settlement is adopted: 2.6, 2.7, 3.1, 3.2, 3.5, 3.6, 3.8, 3-9, 3.10, 3.12, 3.13, 3.14, 3.15, and-3.16.

The Settling Parties agree that PG&E will timely submit its showing in Phase 2 of PG&E's next General Rate Case, scheduled to be the 2007 test year General Rate Case, in accordance with the Rate Case Plan. For example, if PG&E files its application in Phase 1 of its 2007 General Rate Case on December 1, 2005, then PG&E will submit its showing in Phase 2 of its 2007 General Rate Case on March 1, 2006.

2. Marginal Costs

As indicated in the preceding section, the Settling Parties agree not to address electric marginal cost issues in this proceeding in light of the agreement on the outcome of revenue allocation. The Settling Parties expect to address electric marginal cost issues in Phase 2 of PG&E's next General Rate Case, scheduled to be the 2007 test year General Rate Case.

3. Revenue Allocation

a. Five Electric Revenue Requirement Changes Scheduled Before January 1, 2006

The following five electric revenue requirement changes for PG&E are scheduled to take effect in 2005, resulting in approximately a $350 million net decrease in electric revenue requirements for PG&E's bundled customers:

1) 2005 Transmission Access Charge Balancing Account Adjustment (TACBAA) – Approximate $17 million increase Federal Energy Regulatory Commission (FERC) Letter dated March 3, 2005; Advice 2647-E-A, filed on April 21, 2005)

2) 2005 California Department of Water Resources (DWR) Bond Charge and Power Charge Tariff and Remittance Rate – Approximate $225 million decrease (A.00-11-038 et al.; D.05-04-025; Advice 2647-E-A, filed on April 21, 2005)

3) 2005 Energy Resource Recovery Account/Competition Transition Charge (ERRA/CTC) – Approximate $205 million decrease (A.04-06-003 Forecast Phase; D.05-02-040; advice letter not yet filed)

4) Annual Earnings Assessment Proceeding (AEAP) – Approximate $127 million increase (A.03-05-002 et al.; settlement agreement filed April 4, 2005)

5) Energy Recovery Bonds Series 2005-2 (ERB-2) – Estimated $62 million decrease (A.04-07-032; D.04-11-015; advice letter not yet filed)

In the absence of this Settlement, each of these five revenue requirement changes would be allocated to all customer classes, including the residential

customer class, consistent with the general allocation guidance set forth in Paragraph 10 of the Rate Design Settlement Agreement (RDSA) approved by D.04-02-062 in Investigation 02-04-026, and as implemented specifically for rate changes in 2004 and early 2005 (referred to below as "consistent with the RDSA", or the "RDSA methodology"). Generally, the RDSA implements revenue requirement increases or decreases on a system average percentage basis, changing each customer class's revenue by the same percentage on a function by function basis.

Under this Settlement, the Settling Parties agree that these five revenue requirement changes will be allocated to customer classes as follows (even if one or more of the changes takes effect later than now scheduled):

- Allocation of the TACBAA and AEAP revenue requirement increases and the ERB-2 revenue requirement decrease to all customer classes, including the residential customer class, consistent with the RDSA. Within the residential customer class, revenue changes will be allocated entirely to Tier 3 and Tier 4 rates (rates for usage in excess of 130 percent of baseline).
- The DWR and ERRA/CTC revenue requirement decreases will not be allocated to the residential customer class and will be allocated entirely to the non-residential customer classes, so that total bundled residential customer class rates will not change as a result of the DWR and ERRA/CTC revenue requirement decreases. Among the non-residential customer classes, the

decreases will be allocated consistent with the RDSA, on a component by component basis.

- Rate components shown in tariffs for distribution, transmission (as set by FERC), CTC, DWR bond charges, and generation will be revised as a result of the revenue requirement changes discussed above. All components will be revised consistent with the RDSA, except that residential generation rates will be adjusted to achieve the total residential class bundled rates consistent with this agreement. Direct Access (DA) and Departing Load (DL) customers will pay all applicable revised component charges.

Table 1 (next page) shows current average electric rates for each customer class, the approximate average electric rates for each customer class that would have been expected under the five revenue requirement changes specified above in the absence of this Settlement, and the approximate average electric rates for each customer class expected to result cumulatively from these five revenue requirement changes. Table 1 also shows the approximate percentage change in each customer class from the current average rate to the expected average rate without this Settlement, and the percentage change in each customer class from the current average rate to the expected average rate under this Settlement.

Table 1

	Current March 1, 2005 Avg. Rates (cents/kWh) (1)	RDSA Avg. Rates 05 EOY (cents/kWh) (2)	Percent Change RDSA From Current (3)	Settlement Avg. Rates 05 EOY (cents/kWh) (4)	Percent Change Settlement From Current (5)
Bundled					
Residential	12.802	12.500	-2.4%	12.957	1.2%
Small L&P	15.042	14.588	-3.0%	14.309	-4.9%
Medium L&P	14.277	13.563	-5.0%	13.210	-7.5%
E-19	12.855	12.190	-5.2%	11.865	-7.7%
Street Lights	15.129	14.988	-0.9%	14.772	-2.4%
Standby	13.636	13.086	-4.0%	12.832	-5.9%
Agriculture	11.917	11.676	-2.0%	11.493	-3.6%
E-20	10.652	9.995	-6.2%	9.704	-8.9%
Total	12.990	12.512	-3.7%	12.512	-3.7%
Direct Access					
Residential	8.418	8.480	0.7%	8.480	0.7%
Small L&P	8.351	8.530	2.1%	8.530	2.1%
Medium L&P	6.535	6.673	2.1%	6.673	2.1%
E-19	6.068	6.191	2.0%	6.191	2.0%
Agriculture	6.235	6.362	2.0%	6.362	2.0%
E-20	3.924	3.957	0.8%	3.957	0.8%
Total	4.833	4.901	1.4%	4.901	1.4%

To implement this aspect of the Settlement, the Settling Parties agree to take appropriate steps in other relevant proceedings and to support timely Commission outcomes. In particular, the Settling Parties agree to support Advice

2647-E-B to be filed by PG&E the same day as this Settlement. Advice 2647-E-B, a supplemental advice letter superseding Advice 2647-E-A, filed on April 21, 2005, is in compliance with Decision (D.) 05-04-025, *Opinion Allocating the Revised 2005 Revenue Requirement Determination of the California Department of Water Resources (DWR)*, which ordered (at page 5) that "PG&E should change its tariff rates no later than June 1, 2005, for a consolidated rate change including both the DWR power and bond revenue requirements from this decision, as well as for the Transmission Access Charge Balancing Account Adjustment (TACBAA)." Advice 2647-E-A allocated the consolidated revenue requirement change – a net bundled decrease of approximately $208 million – to all customer classes, including the residential customer class, consistent with the RDSA. Advice 2647-E-B allocates the TACBAA revenue requirement change – a bundled increase of approximately $17 million – to all customer classes, including the residential customer class, as required by FERC and consistent with the RDSA, but it allocates the DWR revenue requirement change – a bundled decrease of approximately $225 million – entirely to the non-residential bundled customer classes, so the residential customer class's total bundled rates will not change as a result of the DWR revenue requirement decrease. Among the non-residential customer classes, the DWR decrease will be allocated by the RDSA methodology.

The Settling Parties further agree that revenue allocation and rates provided for in Advice 2647-E-B are conditional upon Commission approval of this Settlement. Advice 2647-E-B shall specify:

1) In the event the Commission rejects this Settlement before putting into effect rates from Advice 2647-E-B, PG&E will put into effect the rates from Advice 2647-E-A as soon as possible; and

2) In the event the Commission puts the rates from Advice 2647-E-B into effect and then rejects the Settlement, PG&E will put into effect the rates from Advice 2647-E-A as soon as possible (provided rates from Advice 2647-E-B have not been superseded by a subsequent rate change) and immediately file a new advice letter to implement the DWR revenue requirement decrease as originally provided for in Advice 2647-E-A, except that PG&E shall further reduce residential rates, and increase non-residential rates, to collect from non-residential customers that portion of the decrease they received on June 1, 2005, that would have been allocated to residential customers but for the terms of this Settlement.

The Settlement's allocation of the DWR revenue decrease on June 1, 2005, only to non-residential customer classes is consistent with both the DWR decision (D.05-04-025) and the RDSA decision (D.04-02-062). The Settlement is consistent with the DWR decision, because under the Settlement's terms the DWR decrease in fact will take effect no later than June 1, 2005, as required by D.05-04-025. The Settlement is consistent with the RDSA decision, because the RDSA's guidance to allocate revenue to all customer classes on a system average percentage basis is effective only "prior to the adoption of rates in Phase 2 of PG&E's 2003 GRC" (D.04-02-062, Attachment A, Paragraph 10), and the Commission decision adopting this Settlement and its allocation of the June 1,

2005, DWR decrease only to non-residential customer classes in fact will be the decision adopting rates in Phase 2 of PG&E's 2003 GRC.

b. A.04-06-024 Rate Changes on January 1, 2006

The Settling Parties agree that electric revenue should be allocated as a result of A.04-06-024 (that is, on an overall revenue-neutral basis), effective January 1, 2006, as follows:

- PG&E's 2006 sales forecast as filed in this proceeding in Supplemental Testimony on May 3, 2005, will be used.
- The bundled residential class allocation shall be set equal to the product of the 2006 forecast residential sales and rates effective January 1, 2004, less a decrement to reflect the residential class share of any rate reduction resulting from the Commission's resolution adopting a rate change for ERB-2.
- The bundled revenue allocation for customer classes other than the residential customer class will be determined as the bundled revenue at present rates for 2005 (at rates in effect at the end of 2005, using PG&E's 2005 sales forecast as provided in A.04-06-024) less the revenue allocated to the residential customer class as set forth above. Due to the general growth in sales, the revenue to be collected from the non-residential classes will be less than the revenue that would be calculated using rates then in effect and the 2006 sales forecast. Accordingly, non-residential customer classes will receive a rate reduction. The reduction will be implemented as a bundled reduction to the

generation component consistent with the RDSA, except as noted below.

- In addition to the changes described above, in compliance with D.04-05-055 (p. A-12), PG&E will shift $2.97 million from the generation component of rates to the nuclear decommissioning portion of rates. This shift will reduce the revenue collected from bundled customers slightly and will increase the revenue collected from DA customers. PG&E will make the associated changes to balancing accounts (as described in Rebuttal Testimony, Exhibit (PG&E-9), pp. 1-15, 1-16) at the time this rate change is implemented.

Table 2 (next page) shows current average electric rates for each customer class, approximate average electric rates for each customer class that would have been expected to result from the five revenue requirement changes described above in the absence of this Settlement, and the rates that are expected to result cumulatively from the five revenue requirement changes described above and from the revenue-neutral A.06-04-024 revenue allocation just described, including the agreement on non-energy charges for the streetlight customer class set forth in the Streetlight Non-Energy Charges section below. Table 2 also shows the approximate percentage change in each customer class from the current average rate to the expected average rate, and the approximate percentage change from the rates that would have been expected to result from

Table 2

	Current March 1, 2005 Avg. Rates (cents/kWh) (1)	RDSA Avg. Rates (cents/kWh) (2)	Percent Change RDSA From Current (3)	Settlement Avg. Rates (cents/kWh) (4)	Percent Change Settlement From Current (5)	Percent Change Settlement From RDSA (6)
Bundled						
Residential	12.802	12.500	-2.4%	13.067	2.1%	4.5%
Small L&P	15.042	14.588	-3.0%	13.858	-7.9%	-5.0%
Medium L&P	14.277	13.563	-5.0%	12.575	-11.9%	-7.3%
E-19	12.855	12.190	-5.2%	11.342	-11.8%	-7.0%
Street Lights	15.129	14.988	-0.9%	14.399	-4.8%	-3.9%
Standby	13.636	13.086	-4.0%	12.402	-9.0%	-5.2%
Agriculture	11.917	11.676	-2.0%	11.275	-5.4%	-3.4%
E-20	10.652	9.995	-6.2%	9.279	-12.9%	-7.2%
Total	12.990	12.512	-3.7%	12.300	-5.3%	-1.7%
Direct Access						
Residential	8.418	8.480	0.7%	8.484	0.8%	0.1%
Small L&P	8.351	8.530	2.1%	8.534	2.2%	0.0%
Medium L&P	6.535	6.673	2.1%	6.664	2.0%	-0.1%
E-19	6.068	6.191	2.0%	6.190	2.0%	0.0%
Agriculture	6.235	6.362	2.0%	6.365	2.1%	0.1%
E-20	3.924	3.957	0.8%	3.984	1.5%	0.7%
Total	4.833	4.901	1.4%	4.915	1.7%	0.3%

the five revenue requirement changes described above in the absence of this Settlement to the expected average rate under this Settlement.

c. Revenue Requirement Changes Scheduled on January 1, 2006

This section sets forth how revenue requirements from the various proceedings listed below will be allocated to each customer class. For the sole purpose of establishing the method to be used to implement these rate changes, PG&E categorizes each revenue requirement change listed below into the following three functional groups: (1) generation-related (G), (2) non-generation-related (NG), and (3) Fixed Transition Amount (FTA)-related. The ratemaking described in this section applies only to the following electric revenue requirement changes scheduled to take effect on January 1, 2006:

Advanced Metering Infrastructure Pre-Deployment (A.05-03-016) - NG, recovered as distribution

- Energy Recovery Bonds (advice letter not yet filed) - G, specifically addressing annual true-up and not issuance of the second series of bonds (ERB-2)
- 2006 Cost of Capital (A.05-05-006, filed on May 9, 2005) - NG for portion recovered as distribution and nuclear decommissioning, and G for portion recovered as generation
- 2006 ERRA Forecast Phase (PG&E to file application on June 1, 2005) - G for portion recovered as CTC (including the Electric Restructuring Cost Account) and G for portion recovered as generation

- 2006 DWR Revenue Requirement Determination (DWR filing due mid-year 2005) - G for portion recovered as DWR bond charge and G for portion recovered as DWR power charge
- 2006 Attrition (A.02-11-017; D.04-05-055; PG&E to file advice letter by October 1, 2005; 2005 electric Attrition revenue requirement increase was $74 million) - NG for portion recovered as distribution and G for portion recovered as generation
- 2006 Energy Efficiency Portfolio (R.01-08-028) (PG&E to file application on June 1, 2005) - NG, recovered as public purpose programs
- 2006 Demand Response Programs (A.05-03-016) (PG&E to file application on June 1, 2005) – determine functional group based on the Commission's decision in the June 1, 2005, application proceeding; NG if the Commission approves recovery as distribution or public purpose programs, and G if the Commission approves recovery as generation
- The 2006 Fixed Transition Amount (FTA) rate change - FTA-related, including the Rate Reduction Bond Memorandum Account (RRBMA) recovered in the Annual Electric True-Up described below
- Transmission rate changes approved by FERC, including the Reliability Service Balancing Account (RSBA) and Transmission Revenue Balancing Account Adjustment (TRBAA) - NG for

portions recovered as transmission and reliability services

- 2006 Annual Electric True-Up (AET) (Resolution E-3906; PG&E advice letter to be filed by September 1, 2005, consolidating amortization of electric balancing accounts and other known revenue requirement changes) - G for portions recovered as CTC, DWR bond, Energy Recovery Bonds, or generation; NG for portions recovered as transmission, reliability services, nuclear decommissioning, public purpose programs, or distribution; and FTA-related for the RRBMA

The Settling Parties agree that electric rate changes listed above will be in addition to the five electric revenue requirement changes scheduled to take effect before January 1, 2006, and to A.04-06-024 rate changes effective January 1, 2006, as set forth earlier, and that this Settlement does not make any assumptions about the direction or size of the listed revenue requirement changes scheduled to take effect on January 1, 2006.

For each of the two functional groups, G and NG, PG&E will calculate the revenue that would be allocated to each customer class consistent with the RDSA, and the Settling Parties agree to the following revenue allocation:

A. For each functional group, if the total bundled revenue allocated to the residential class is an increase to bundled revenue at present rates (i.e., a residential net bundled increase), then the increase to G or NG functional groups will be offset with net decreases to the residential class from revenue requirement changes to the FTA-

related functional group. A decrease in the bundled residential class allocation as a result of FTA-related revenue requirements will be applied first to increases to the NG functional group (if any) and second to increases to the G functional group (if any). The net remaining increase to G or NG will then be allocated to all customer classes, including the residential customer class, consistent with the RDSA. Within the residential customer class, revenue changes will be allocated entirely to Tier 3 and Tier 4 rates (rates for usage in excess of 130 percent of baseline).

B. For each functional group, if the total bundled revenue allocated to the residential class is a decrease to bundled revenue at present rates, then the revenue decrease will not be allocated to the residential customer class and will be allocated entirely to the non-residential customer classes, so residential customer class rates will not change as a result of the revenue requirement decrease Reductions that would otherwise have been allocated to the residential customer class will be allocated by functional group to other customer classes as follows:

- Net reductions to the G functional group will be allocated to non-residential customer classes consistent with the RDSA based on generation revenue (excluding CTC, DWR bond, and Energy Recovery Bonds), and will be expressed as a reduction to generation rates.

- Net reductions to the NG functional group and FTA-related functional group (after FTA decreases have been used to offset increases as described above) will be allocated to non-residential customer classes based on the sum of revenue for distribution, transmission, reliability services, public purpose programs, and nuclear decommissioning revenues, and will be expressed as a reduction to distribution rates.

C. All rate components will be revised based on the change in revenue requirement for each component and the RDSA methodology, except that residential generation and distribution rates will be adjusted to achieve the total bundled residential class rates consistent with this agreement. DA and DL customers will pay all applicable revised component charges.

If any of these electric revenue requirement changes are delayed and do not take effect until after January 1, 2006, the Settling Parties agree the following provisions for delayed changes should apply for the purpose of adjusting rates to achieve the same outcome as if the changes had taken place on schedule. For each functional group (generation or non-generation), PG&E will calculate the revenue that would be allocated to each customer class consistent with the RDSA as a result of each specified delayed revenue requirement change or balancing account amortization, and the Settling Parties agree to the following revenue allocation:

For each functional group, if the residential class received a net bundled

increase on January 1, 2006, then:

- For each functional group, any further revenue increases relative to bundled residential revenue at present rates shall be allocated to the residential class as described in paragraph A above.
- For each functional group, if subsequent to any increases described in this section, a revenue requirement change would result in a decrease to residential bundled customers relative to bundled residential revenue at present rates under the RDSA methodology, bundled residential customers shall be allocated a decrease up to the amount of the increases previously received. Thereafter, decreases that would have been allocated to the bundled residential customers will be allocated to the other classes as described in paragraph B above.

For each functional group, if the residential class did not receive a net bundled increase on January 1, 2006, then:

- For each functional group, any further decreases to the residential class shall be allocated to the other classes as described in paragraph B above.
- For each functional group, if subsequent to implementing any revenue requirement decreases that resulted in no change to residential rates as prescribed in paragraph B, a revenue requirement increase would result in an increase to residential

bundled customers relative to bundled residential revenue at present rates under the RDSA methodology, bundled residential customers shall be allocated an increase only to the extent the increase exceeds the amount of the decreases that would have been allocated previously to bundled residential customers under the RDSA. Non-residential customer classes will then be allocated a change in revenue based on the RDSA methodology after determining the change to the residential class allocation. Net reductions allocated to non-residential customer classes shall be calculated in accordance with paragraph B above.

d. Other Revenue Requirement Changes

The Settling Parties agree that revenue allocation for electric revenue requirement changes other than those expressly listed in this Settlement will be governed by otherwise applicable rules and decisions, not by the provisions of this revenue allocation section of the Settlement. Specifically, electric revenue requirement charges scheduled to take effect after January 1, 2006, and before the effective date of the Commission's decision in Phase 2 of PG&E's next general rate case, will be allocated to all customer classes, including the residential customer class, consistent with the RDSA, unless otherwise ordered by the Commission. Any rate changes approved by FERC will be implemented as that agency directs. Within the residential customer class, revenue requirement changes will be allocated entirely to Tier 3 and Tier 4 rates (rates for usage in excess of 130 percent of baseline).

e. Other Revenue Allocation Issues

The Settling Parties agree to defer any remaining electric revenue allocation issues to Phase 2 of PG&E's 2007 test year General Rate Case, except that the BART and Sierra Pine issues identified above as issues 2.6 and 2.7 are unresolved and not deferred.

4. Rate Design

a. Generally

Except for rate design issues resolved by this Settlement, the Settling Parties agree in good faith to discuss timely potential settlement of all electric rate design issues in this proceeding, to regularly apprise ALJ Mattson of the status of rate design settlement discussions, and to cooperate in setting a procedural schedule for electric rate design issues that are not settled so they may be litigated and decided by the Commission for an effective date no later than January 1, 2006.

b. Funding for Direct Access Cost Responsibility Surcharge Undercollection

In D.03-07-030, the Commission provided that the cost of the DA cost responsibility surcharge (CRS) undercollection should be funded by core and non-core customers in proportion to each group's DA participation. In D.04-02-062, the Commission adopted the RDSA, which established rates for accounting purposes that reflected this proportional allocation of costs between core and non-core bundled customers. In this proceeding, the Settling Parties agree that non-core bundled customers have funded more than their share of the DA CRS undercollection and that the preliminary statement rates used for accounting

purposes for core and non-core bundled customers should be equal until the Commission has an opportunity to review how the DA CRS is funded. Therefore, the Settling Parties agree to set the Power Charge Collection Balancing Account (PCCBA), found in Part DG of the PG&E's electric Preliminary Statement, at the same level for core and non-core bundled customers. In addition, rates set forth in the Bundled Financing Allocation Tracking Account (BFATA), found in Part DM of the PG&E's electric Preliminary Statement, to track contributions from bundled core and bundled non-core customers will be set to zero until the Commission reviews the status of the Direct Access Cost Responsibility Surcharge (DA CRS) undercollection and how it is funded among core and non-core bundled customers. The Settling Parties further agree that this change to PCCBA and BFATA rates should occur on the date rates from this proceeding are implemented. Outstanding balances should be addressed in the DA Suspension proceeding, Rulemaking (R.) 02-01-011, or as the Commission may direct.

c. Nonfirm Program Incentives

The Settling Parties agree that the incentive for service under the nonfirm program shall be retained at the absolute level of credit currently in effect as shown in Schedules E-19 and E-20, until the Commission reviews this issue in Phase 2 of PG&E's next General Rate Case or until the Commission separately considers nonfirm issues (e.g., in the statewide Critical Peak Pricing proceeding, A.05-01-016 et al.). At the time rates are implemented pursuant to a decision in A.04-06-024, PG&E will restate the nonfirm program terms and credits in a separate rate schedule which will apply as a rider to the otherwise applicable E-19 or E-20 rate schedule.

d. Phase 2 of the Baseline Rulemaking

The Settling Parties agree that shortfalls resulting from programs adopted in Phase 2 of the Baseline Rulemaking (D.04-02-057 in R.01-05-047) shall be recovered from the residential class by function, based on the RDSA method. Programs adopted by the Commission in D.04-02-057 that will have accrued balances by the end of 2005 include the Family Electric Rate Assistance (FERA) program and the increase to baseline quantities due to excluding seasonal residences from the baseline quantity calculation. Further, the Settling Parties agree that tracking undercollections for the change to baseline quantities due to excluding seasonal residences from the baseline quantity calculation will no longer be required once rates resulting from a decision in this proceeding are implemented.

e. Residential Generation Revenue Memorandum Account

In Resolution E-3906, the Commission required PG&E to track revenue that is collected in Tier 3 and Tier 4 residential rates that would have otherwise been collected in Tier 1 and Tier 2 rates but for the rate restrictions established by Assembly Bill (AB) 1x (Water Code Section 80110). That resolution further stated that the purpose of tracking such revenue was to provide the Commission an opportunity to consider whether to reallocate that revenue among customer groups in A.04-06-24. The Settling Parties agree that the level of Tier 3 and Tier 4 rates resulting from Resolution E-3906 was reasonable. Further, the Settling Parties agree that the Residential Generation Revenue Memorandum Account, found in Part DR of PG&E's electric Preliminary Statement, can be eliminated.

f. Electric Master Meter Discount

1. The Master-Meter Discount For Electric Schedule ET

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. Marginal Cost Methodology

It is appropriate to use the "replacement cost method" rather than the “new customer only” (NCO) method only for calculating equipment costs used to establish the master-meter discount, because master-meter customers have the unique characteristic of zero growth by virtue of a statutory prohibition against new submetered parks in Public Utilities Code Section 2791(c). The replacement cost method establishes a value for customer hookup equipment by multiplying the initial investment by the utility's real economic carrying charge.

3. EPMC Scaling Factor

No agreement was reached on whether it is appropriate to adjust a master-meter discount by an equal percent of marginal cost (EPMC) scaling factor; however, the Settling Parties agree that if any Settling Party advocates the use of an EPMC scaler in any future proceeding, that party shall advocate only a scaling to recover the utility's embedded customer costs for purposes of the master-meter discount. The Settling Parties agree not to advocate scaling of the embedded distribution demand costs in any future proceeding that addresses mobile home park master-meter discounts.

4. Diversity Benefit Study

On or before July 1, 2007, PG&E shall update the data used to calculate the diversity benefit adjustment using sample metered data from 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.

5. The Master-Meter Discount For Electric Schedule ES

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 ($3.22 per unit per month). The net master-meter benefit is based on the uncontested proposal in PG&E's February 18, 2005, update testimony on master-meter discounts, and shall be fixed at these levels until the next applicable GRC.

6. This Result Is Reasonable, Consistent With Law, and In The Public Interest

The calculation of the master meter discount in this Settlement uses a respected marginal cost method, the "replacement cost method," on the theory that master meter customers have the unique characteristic of zero growth by virtue of a statutory prohibition against new submetered mobile home parks. The Settlement addresses specifics such as application of an EPMC scaler and calculation of the diversity benefit adjustment. As was detailed in the testimony of WMA, PG&E and TURN, there was a range of possible outcomes based upon the different methodologies proposed by each party and the opposing sentiments

related to the additional items such as the diversity benefit adjustment and an EPMC scaler. This Settlement represents a reasoned decision of the parties interested in the master meter discount to not apply an EPMC scaler, but to leave the option open for future proceedings. Further, although WMA did not approve of a diversity benefit adjustment, the amount agreed upon is fair and commits PG&E to update the data used to calculate the diversity benefit adjustment, which addresses WMA's main concern with application of the adjustment. Therefore, this settlement falls within the range of possible outcomes of continued litigation in this case.

7. Table

Table 3 presents the discounts for Schedules ES and ET.

TABLE 3

PRESENT AND RECC MARGINAL COST-BASED ELECTRIC MASTER-METER DISCOUNTS (PER MONTH, PER UNIT)

		Present Discounts		Proposed Discounts		
Line No	Rate Schedule	Present Discount (a)	Daily Equivalent	Discount (b)	Daily Equivalent	Line No
1	ET – Mobile Home Park Service	$10.44	$0.34300	$11.54	$0.379	1
2	ES – Multifamily Service	$3.22	$0.10579	$3.22	$0.10579	2

g. Streetlight Non-Energy Charges

Tariff installation, clearance, and compliance provisions will become effective March 1, 2006, to allow training of PG&E Service Planning groups

system-wide, and to allow time for necessary changes in estimating programs.

1. Marginal Cost

For PG&E's streetlight marginal customer costs, the hookup cost should be $350, as shown in PG&E's April 8, 2005, Corrections To Prepared Marginal Cost Update Testimony.

2. Non-Conforming Load

PG&E will waive non-conforming load requirements subject to the following conditions:

a. Connections or devices installed must not cause General Order 95 infractions or conflict with other General Order clearance requirements;

b. For governmental agencies only, no street light or street light circuit shall have more then 50 watts of additional non street light load connected on LS-2 facilities;

c. PG&E will increase the incidental load proposal in TC-1 and LS-3 schedules to 5 percent of total connected load.

3. LS-3 Meter Charge

The LS3 meter charge will remain at the current level ($3.00/month).

4. Photocontrols

If a new standard for photocontrols is adopted for LS-2, then the same standard should apply to LS-1 and OL-1, and PG&E will modify the tariff language in LS-1, LS-2, and OL-1 accordingly.

5. Revenue Requirement for Non-Energy Streetlight Charges

For PG&E's streetlight revenue requirement used to set non-energy charges:

a. The revenue requirement is $20.068 million. (No specific streetlight revenue requirement was adopted in the GRC Phase 1 settlement.)

b. The common rate base allocated to street lighting is decreased as shown in CAL-SLA's Table 6 in the CAL-SLA testimony at page 18.

c. The Revenue Adjustment Factor (RAF) is based on return on equity and capital structure from D.04-12-047, as shown in CAL-SLA testimony at pages 19-20.

d. Marginal customer costs (rather than embedded costs) are used for customer accounting and administrative and general (A&G) expenses, as shown in CAL-SLA testimony at page 20.

e. As shown in CAL-SLA testimony at page 10, no Common Plant is allocated to LS-2.

f. PG&E's 2005 Lamp Count is used, as shown in CAL-SLA testimony at page 3.

6. The Settlement Is Reasonable, Consistent With Law, And In the Public Interest

This portion of the Settlement regarding streetlight non-energy changes is the result of negotiations between PG&E and CAL-SLA, the only two parties with an expressed interest in rate design within the streetlight customer class.

However, all Settling Parties have had the opportunity to review the streetlight revenue requirement outcome, which affects the amount of revenue allocated to each of the other customer classes. Agreement on this result by all the Settling Parties, not just PG&E and CAL-SLA, demonstrates the soundness of this portion of the Settlement.

7. Tables

PG&E's simplified, non-energy streetlight charges shall be used and shall include the following three components:

- A universal charge;
- The remaining operations and maintenance (O&M)expense charge; and
- A plant-related charge.

Table 4 shows how the agreed upon revenue requirement is divided into these three components. Table 5 shows the allocation of plant-related expenses to the streetlight schedules. Note, the simplified non-energy streetlight model assumes the same rate, based on the most common lamp type (i.e., lamp voltage, lamp type, such as high pressure sodium vapor, and lamp wattage), for each lamp type. Table 6 shows the allocation of the remaining O&M expenses (excluding O&M already captured in the universal charge) to the streetlight schedules. Finally, the three rate components are shown in Table 7 with the total agreed upon set of non-energy streetlight rates.

TABLE 4
STREETLIGHT REVENUE REQUIREMENT MAPPED TO UNIVERSAL, O&M AND PLANT-RELATED CATEGORIES

Line No.		Revenue Requirement	(000 $)	**4.7%** A&G	**25.0%** Common Plant	Sum	2005 Lamp Count	$/lamp /month
1	Universal Charges							
2		FERC Ac. 596 - Dist. Maps, Records, Supv., Eng.	$366	$17		$383		
3		Customers Accounts	$1,183	$56		$1,239		
4	Subtotal Universal					$1,623	711,707	$0.19
5	Remaining Distribution O&M - burnouts and other		$4,244	$201		$4,445	249,560	$1.48
6	Subtotal		$5,793	$275		$6,068		
7	Plant and misc.							
8		Plant related with common plant	$12,363		$1,446	$13,809		
9		Uncollectibles	$40			$40		
10		Franchise Requirements	$151			$151		
11	Subtotal Plant and misc.		$12,554			$14,000	202,876	
12	Total RO					$20,068		

TABLE 5

ALLOCATION OF PLANT-RELATED EXPENSES TO STREETLIGHT SCHEDULE

Line No.	Rate Schedule	Typical Lamp	2005 Lamp Count	Plant Charge (with Common)	Total Charge per month	Weight	Allocated RRQ	Ave Charge per month
1	LS-1A	70 W 120 V HPSV	69,319	$5.68	$393,919	0.3425	$4,795	$5.76
2	LS-1B	175 W Mercury Vapor	36	$2.69	$97	0.0001	$1	$2.73
3	LS-1C	70 W 120 V HPSV	20,690	$2.93	$60,529	0.0526	$737	$2.97
4	LS-1D	70 W 120 V HPSV	14,534	$6.11	$88,749	0.0772	$1,080	$6.19
5	LS-1E	70 W 120 V HPSV	35,121	$5.57	$195,511	0.1700	$2,380	$5.65
6	LS-1F	70 W 120 V HPSV	17,232	$6.55	$112,918	0.0982	$1,374	$6.65
7	LS-2A		462,126	-	-		$0	
8	LS-2B		13,454	-	-		$0	
9	LS-2C		33,230	-	-		$0	
10	OL-1	100 W 120 V HPSV	25,783	$5.77	$148,805	0.1294	$1,811	$5.85
11	CCSF	100 W 240 V HPSV	20,161	$7.42	$149,618	0.1301	$1,821	$7.53
12	SP-2A1		21	-	-		$0	
13			711,707		$1,150,145	1.0000	$14,000	

TABLE 6
ALLOCATION OF THE REAMINING O&M EXPENSES TO STREETLIGHT SCHEDULE

Line No.	Rate Schedule	Typical Lamp	2005 Lamp Count	O&M Charge	Total Charge per month	Weight	Allocated RRQ	Ave Charge per month
1	LS-1A	70 W 120 V HPSV	69,319	$1.53	$106,305	0.2807	$1,248	$1.50
2	LS-1B	175 W Mercury Vapor	36	$1.73	$62	0.0002	$1	$1.70
3	LS-1C	70 W 120 V HPSV	20,690	$1.53	$31,730	0.0838	$372	$1.50
4	LS-1D	70 W 120 V HPSV	14,534	$1.53	$22,289	0.0589	$262	$1.50
5	LS-1E	70 W 120 V HPSV	35,121	$1.53	$53,860	0.1422	$632	$1.50
6	LS-1F	70 W 120 V HPSV	17,232	$1.53	$26,426	0.0698	$310	$1.50
7	LS-2A		462,126	$0.00	$0	0.0000	$0	$0.00
8	LS-2B	70 W 120 V HPSV	13,454	$1.23	$16,502	0.0436	$194	$1.20
9	LS-2C	70 W 120 V HPSV	33,230	$1.53	$50,946	0.1345	$598	$1.50
10	OL-1	100 W 120 V HPSV	25,783	$1.53	$39,540	0.1044	$464	$1.50
11	CCSF	100 W 240 V HPSV	20,161	$1.54	$31,070	0.0820	$365	$1.51
12	SP-2A1		21	$0.00	$0	0.0000	$0	$0.00
13			711,707		$378,731	1.0000	$4,445	

TABLE 7
RESULTING NON-ENERGY STREETLIGHT RATES

Line No.	Rate Schedule	2005 Lamp Count	Plant Charge per Month	Universal Charge	O&M Charge	Total per month	2005 Annual Revenues ($000)	2006 Lamp Count	2006 Annual Revenues ($000)
1	LS-1A	69,319	$5.764	$0.190	$1.500	$7.454	$6,201	68,657	$6,141
2	LS-1B	36	$2.725	$0.190	$1.696	$4.611	$2	35	$2
3	LS-1C	20,690	$2.967	$0.190	$1.500	$4.657	$1,156	21,238	$1,187
4	LS-1D	14,534	$6.194	$0.190	$1.500	$7.884	$1,375	14,647	$1,386
5	LS-1E	35,121	$5.647	$0.190	$1.500	$7.337	$3,092	35,127	$3,093
6	LS-1F	17,232	$6.647	$0.190	$1.500	$8.337	$1,724	16,882	$1,689
7	LS-2A	462,126	$0.000	$0.190	$0.000	$0.190	$1,054	474,397	$1,082
8	LS-2B	13,454	$0.000	$0.190	$1.200	$1.390	$224	14,104	$235
9	LS-2C	33,230	$0.000	$0.190	$1.500	$1.690	$674	36,130	$733
10	OL-1	25,783	$5.854	$0.190	$1.500	$7.544	$2,334	25,656	$2,323
11	CCSF	20,161	$7.528	$0.190	$1.507	$9.225	$2,232	20,161	$2,232
12	Subtotal	711,686						727,034	
13									
14	SP-2A1	21		$0.190		$0.190	$0	21	$0
15	Total	711,707					$20,068	727,055	$20,101

VI. 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 shall become effective among the Settling Parties on the date the last Settling Party executes the Settlement as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Settlement on behalf of the Settling Parties they represent.

This Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Agricultural Energy Consumers Association

By: Michael Boccadoro

Title: Executive Director

Building Owners and Managers Associations of San Francisco and of California

By: _____

Title: _____

California City-County Street Light Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: _____

California Large Energy Consumers Association

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Agricultural Energy Consumers Association

By: _____

Title: _____

Building Owners and Managers Associations of San Francisco and of California

By: Bill F. Poletti

Title: President, Economic Sciences Corp.

California City-County Street Light Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: _____

California Large Energy Consumers Association

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Agricultural Energy Consumers Association

By: _____

Title: _____

Building Owners and Managers Associations of San Francisco and of California

By: _____

Title: _____

California City-County Street Light Association

By: _____

Title: Attorney

California Farm Bureau Federation

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California Large Energy Consumers Association

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Title: _____

Building Owners and Managers Associations of San Francisco and of California

By: _____

Title: _____

California City-County Street Light Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: Associate Counsel

California Large Energy Consumers Association

California Large Energy Consumers Association

By: William H. Booth

Title: Counsel

California Manufacturers & Technology Association

By: _____

Title: _____

California Retailers Association

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users

By: _____

Title: _____

Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

By: _____

Title: _____

California Manufacturers & Technology Association

By: Kathy R. McCann

Title: Attorney

California Retailers Association

By: _____

Title: _____

Cogeneration Association of California and
Energy Producers and Users

By: _____

Title: _____

Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

By: _____

Title: _____

California Manufacturers & Technology Association

By: _____

Title: _____

California Retailers Association

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Coalition

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East Bay Municipal Utility District

By: _____

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Energy Users Forum

By: _____

Title: _____

California Large Energy Consumers Association

By: _____

Title: _____

California Manufacturers & Technology Association

By: _____

Title: _____

California Retailers Association

By: _____

Title: _____

Cogeneration Association of California and
Energy Producers and Users Coalition

By: [illegible]

Title: Counsel

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

By: _____

Title: _____

California Manufacturers & Technology Association

By: _____

Title: _____

California Retailers Association

By: _____

Title: _____

Cogeneration Association of California and
Energy Producers and Users

By: _____

Title: _____

Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: Richard B. Sykes

Title: Manager of Water System

Energy Users Forum

By: _____

Title: _____

By: _____

Title: _____

California Manufacturers & Technology Association

By: _____

Title: _____

California Retailers Association

By: _____

Title: _____

Cogeneration Association of California and
Energy Producers and Users

By: _____

Title: _____

Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: Carolyn M. Kehreis

Title: Consultant To EUF

Indicated Commercial Parties

By: Randall W. Keen
Manatt, Phelps & Phillips, LLP, Attorneys for
Title: Indicated Commercial Parties

Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

The Western Manufactured Housing
Communities Association

By: _____

Title: _____

Indicated Commercial Parties

By: _____

Title: _____

Office of Ratepayer Advocates

By: [illegible]

Title: Deputy Director

Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: _____

Wal-Mart Stores, Inc.

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Indicated Commercial Parties

By: _____

Title: _____

Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: Andrew L. Niven

Title: Attorney

The Utility Reform Network

By: _____

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Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: Staff Attorney

Wal-Mart Stores, Inc.

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Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: Attorney of Record

The Western Manufactured Housing Communities Association

By: _____

Title: _____

Indicated Commercial Parties

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Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

The Western Manufactured Housing Communities Association

By: _____

Title: Counsel for WMA

(END OF APPENDIX B)

APPENDIX C

SUPPLEMENTAL RESIDENTIAL SETTLEMENT

SUPPLEMENTAL RESIDENTIAL SETTLEMENT

IN APPLICATION 04-06-024

I. SUPPLEMENTAL RESIDENTIAL SETTLEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this settlement (Settling Parties) agree on a mutually acceptable outcome to issues regarding rates for residential customers in Application (A.) 04-06-024, 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 Application 04-06-024 filed in this proceeding on May 13, 2005 (May 13 Settlement), in that it uses the revenue allocation agreed to in the May 13 Settlement and addresses residential issues that were not resolved in the May 13 Settlement. The Settling Parties intend that the complementary outcomes of this Residential Settlement and the May 13 Settlement be consolidated in the Commission's final decision in this proceeding.

II. RESIDENTIAL SETTLEMENT PARTIES

The Settling Parties are as follows:

Office of Ratepayer Advocates (ORA)

Pacific Gas and Electric Company (PG&E)

The Utility Reform Network (TURN)

III. RESIDENTIAL SETTLEMENT CONDITIONS

The Settling Parties agree that this Residential Settlement resolves the specified issues raised in A.04-06-024 by the Settling Parties, subject to the following reservations:

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 May 13 Settlement and incorporates that agreement by reference. ORA, PG&E, and TURN are signatories to the May 13 Settlement.

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, in accordance with Rule 51.1(e).

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 and actively support timely Commission approval of this Residential Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 May 13 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 May 13 Settlement, the Settling Parties reserve their rights under Rule 51.7.

IV. SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

> On August 27, 2004, the *Scoping Memo And Ruling of Assigned Commissioner* (ACR) stated: "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding). …

The three general subjects of the application are marginal costs, revenue allocation and rate design." The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 13, 2005, sixteen parties to this proceeding filed the May 13 Settlement regarding marginal cost and revenue allocation issues as well as Streetlight and Submetering rate design issues, and they stated that discussions would continue in an effort to reach agreement on the remaining rate design issues. The May 13 Settlement was filed before all rate design issues were resolved due to a June 1, 2005 deadline relating to a key feature of the May 13 Settlement.

After several discussions, on May 31, 2005, parties to the residential rate

design settlement discussions reached an agreement in principle, building from the residential revenue allocation agreed to in the May 13 Settlement.

V. RESIDENTIAL SETTLEMENT TERMS

1. Generally

The Settling Parties agree that the primary purpose of rate design for the residential class is to take the revenue allocation reached for that class in the May 13 Settlement and ensure that it is fully recovered through residential 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 rates set forth herein are consistent with the revenue allocation set forth in Table 2 of the May 13 Settlement, and that the actual rates calculated in accordance with this Residential Settlement may be somewhat different than those set forth below.

No later than June 9, 2005, PG&E will serve a comparison exhibit showing the impact of this Residential Settlement in relation to the litigation positions of PG&E and ORA, as required by Rule 51.1(c).

The Settling Parties agree that all testimony served prior to the date of this Residential Settlement that addresses the residential rate design 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 will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.04-06-024. 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 Residential Settlement or the May 13 Settlement.

In terms of the 36 specific issues identified in Attachment A to the ACR and in subsequent ALJ rulings, this Residential Settlement resolves Rate Design issue 3.5 and portions of Rate Design issue 3.6 (for the residential customer class only).

2. A.04-06-024 Residential Rate Changes on January 1, 2006

The Settling Parties agree that rates to collect the revenue allocated to the residential customer class under the May 13 Settlement on an overall revenue-neutral basis shall be designed as set forth below, and that these rates shall serve as the starting point for determining the changes to rates necessary to collect the adopted revenue requirement on January 1, 2006.

1. Residential California Alternative Rates for Energy (CARE) rates shall remain unchanged. CARE usage in excess of 130 percent of baseline shall continue to be billed at the current CARE Tier 2 rate.

2. Residential baseline quantities shall be revised in accordance with PG&E's testimony, Assembly Bill (AB) 1x permitting. The electric "target" baseline quantities shown in testimony in Exhibit (PG&E-4) in Table 2A-3 shall be adopted. PG&E shall file an advice letter in Spring 2006 to "phase-in" from current to target baseline quantities on May 1, 2006, the start date of the electric summer season. The baseline phase-in shall comply with existing 5 percent single-family and 10 percent multifamily baseline quantity phase-in bill increase

limitation rules.

3. Gas “target” baseline quantities shown in Table 2A-3 will be revised in a late-filed Settlement exhibit to reflect the new summer and winter seasonal realignment proposed in PG&E’s Biennial Cost Allocation Proceeding (BCAP), with an advice letter filed in early 2006 to “phase-in” from then current to target gas baseline quantities on April 1, 2006, the new BCAP start date for the summer gas season.

4. Prior to a decision in the 2007 GRC Phase 2 proceeding, rates for usage in excess of 130 percent of baseline for non-CARE customers shall be determined by setting the Tier 3, 4, and 5 surcharges the same on all applicable non-CARE residential rate Schedules E-1, E-6, E-7, E-8, and E-9, as well as applicable multifamily Schedules EM, ES, ESR, and ET.

5. Effective May 1, 2006, rates for medical baseline customers shall remain unchanged for usage below 130 percent of baseline, but a new Tier 3 rate equal to the non-CARE Tier 3 rate shall apply to all medical baseline usage in excess of 130 percent of baseline. Tier 4 and 5 rates shall not apply to medical baseline usage. In order to provide relief to medical baseline customers who are currently ineligible for PG&E’s Schedule E-FERA (Family Electric Rate Assistance program), in the compliance advice letter made pursuant to a final decision in this proceeding, PG&E shall make the following tariff revision to Schedule E-FERA Special Condition 2 effective May 1, 2006: delete the phrase “or medical baseline program.”

6. Time of use (TOU) Schedules E-7, EL-7, E-A7, and EL-A7 shall be

closed to new enrollment on May 1, 2006. Replacement Schedules E-6 and EL-6, which are revenue neutral with the residential class, shall be opened on May 1, 2006, for all new TOU enrollment.

7. The current Schedules E-7, EL-7, E-A7, and EL-A7 TOU Installation Charge shall be eliminated on May 1, 2006, and only the two current ongoing daily TOU meter charges shall be continued at their current level, on Schedules E-7, EL-7, E-A7, EL-A7, E-6, and EL-6.

8. The composition of total rates by tier shall be designed such that the rate differential by tier shall be made up of both generation and distribution, within each tier in the same proportion as total distribution to generation revenues allocated to the schedule.

9. The current calculation of residential CARE rates where the 20 percent discount is applied to lower the distribution charges, and generation surcharges are waived, shall be retained.

10. The current employee discount shall apply the 25 percent discount to the full Tier 1 rate, plus 25 percent of the full Tier 2 rate for all usage over baseline.

11. The rates shown below are developed to collect the revenue allocated to the residential class set forth in Table 2 (column 4) of the May 13 Settlement. Adopted revenue requirements shall be applied to these initial rates to determine rates effective in 2006. These rates are the best estimate of the rates that would be calculated based on actual Commission decisions at that time. However, the actual rates may be somewhat different than those shown below. Illustrative

rates for Schedules E-1, E-6, E-7, E-A7, E-8, E-9, EM, ES, ESR, ET, and all CARE counterparts are presented in Attachment A.

4

VI. 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.

This Residential Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Office of Ratepayer Advocates

By: [illegible]

Title: Deputy Director

Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: _____

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Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: Adrian L. Niven

Title: Attorney

The Utility Reform Network

By: _____

Title: _____

VI. SETTLEMENT EXECUTION

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Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

The Utility Reform Network

By: _____

Title: Staff Attorney

ATTACHMENT A

To Supplemental Residential Settlement In Application 04-06-024

Illustrative January 1, 2006 Residential Rates

ORA-PG&E-TURN GRC Phase 2 Residential Settlement Rates

June 1, 2005

	E-1	E-1 Medical	EL-1 (CARE)
Tier 1	$0.11430	$0.11430	$0.08316
Tier 2	$0.12989	$0.12989	$0.09563
Tier 3	$0.17743	$0.17743	$0.09563
Tier 4	$0.22136	$0.17743	$0.09563
Tier 5	$0.24147	$0.17743	$0.09563

	E-6 Smr Pk	E-6 Smr Part	E-6 Smr Off	E-6 Wtr Part	E-6 Wtr Off
Tier 1	$0.20852	$0.11168	$0.09412	$0.12407	$0.10036
Tier 2	$0.22411	$0.12727	$0.10971	$0.13966	$0.11595
Tier 3	$0.27165	$0.17481	$0.15725	$0.18720	$0.16349
Tier 4	$0.31558	$0.21874	$0.20118	$0.23113	$0.20742
Tier 5	$0.33569	$0.23885	$0.22129	$0.25124	$0.22753

	EL-6 Smr Pk	EL-6 Smr Part	EL-6 Smr Off	EL-6 Wtr Part	EL-6 Wtr Off
Tier 1	$0.17849	$0.08165	$0.06409	$0.09404	$0.07033
Tier 2	$0.19096	$0.09412	$0.07656	$0.10651	$0.08280
Tier 3	$0.19234	$0.09549	$0.07793	$0.10788	$0.08417
Tier 4	$0.19361	$0.09676	$0.07920	$0.10915	$0.08544
Tier 5	$0.19419	$0.09734	$0.07978	$0.10973	$0.08602

	E-7 Smr Pk	E-7 Smr Off	E-7 Wtr Pk	E-7 Wtr Off
Tier 1 *	$0.27813	$0.07105	$0.09913	$0.07407
Tier 2	$0.29372	$0.08664	$0.11472	$0.08966
Tier 3	$0.34126	$0.13418	$0.16226	$0.13720
Tier 4	$0.38519	$0.17811	$0.20619	$0.18113
Tier 5	$0.40530	$0.19822	$0.22630	$0.20124

Medical	E-7 Smr Pk	E-7 Smr Off	E-7 Wtr Pk	E-7 Wtr Off
Tier 1 *	$0.27813	$0.07105	$0.09913	$0.07407
Tier 2	$0.29372	$0.08664	$0.11472	$0.08966
Tier 3	$0.34126	$0.13418	$0.16226	$0.13720
Tier 4	$0.34126	$0.13418	$0.16226	$0.13720
Tier 5	$0.34126	$0.13418	$0.16226	$0.13720

	EL-7 Smr Pk	EL-7 Smr Off	EL-7 Wtr Pk	EL-7 Wtr Off
Tier 1 *	$0.26813	$0.06105	$0.08913	$0.06407
Tier 2	$0.28372	$0.07664	$0.10472	$0.07966
Tier 3	$0.28372	$0.07664	$0.10472	$0.07966
Tier 4	$0.28372	$0.07664	$0.10472	$0.07966
Tier 5	$0.28372	$0.07664	$0.10472	$0.07966

	E-A7 Smr Pk	E-A7 Smr Off	E-A7 Wtr Pk	E-A7 Wtr Off

Tier 1 *	$0.30701	$0.06689	$0.09834	$0.07415
Tier 2	$0.32260	$0.08248	$0.11393	$0.08974
Tier 3	$0.37014	$0.13002	$0.16147	$0.13728
Tier 4	$0.41407	$0.17395	$0.20540	$0.18121
Tier 5	$0.43418	$0.19406	$0.22551	$0.20132

	EL-A7 Smr Pk	EL-A7 Smr Off	EL-A7 Wtr Pk	EL-A7 Wtr Off
Tier 1 *	$0.29701	$0.05689	$0.08834	$0.06415
Tier 2	$0.31260	$0.07248	$0.10393	$0.07974
Tier 3	$0.31260	$0.07248	$0.10393	$0.07974
Tier 4	$0.31260	$0.07248	$0.10393	$0.07974
Tier 5	$0.31260	$0.07248	$0.10393	$0.07974

	E-8 Summer	E-8 Winter	EL-8 Summer	EL-8 Winter
Tier 1	$0.11815	$0.07577	$0.08624	$0.05234
Tier 2	$0.11815	$0.07577	$0.08624	$0.05234
Tier 3	$0.16569	$0.12331	$0.08624	$0.05234
Tier 4	$0.20962	$0.16724	$0.08624	$0.05234
Tier 5	$0.22973	$0.18735	$0.08624	$0.05234

E-9 A	Summer Peak	Summer Part	Summer Off	Winter Part	Winter Off
Tier 1 *	$0.26809	$0.08836	$0.03406	$0.08824	$0.04236
Tier 2	$0.28368	$0.10395	$0.04965	$0.10383	$0.05795
Tier 3	$0.33122	$0.15149	$0.09719	$0.15137	$0.10549
Tier 4	$0.37515	$0.19542	$0.14112	$0.19530	$0.14942
Tier 5	$0.39526	$0.21553	$0.16123	$0.21541	$0.16953

E-9 B	Summer Peak	Summer Part	Summer Off	Winter Part	Winter Off
Tier 1 *	$0.26408	$0.08435	$0.04057	$0.08468	$0.04819
Tier 2	$0.27967	$0.09994	$0.05616	$0.10027	$0.06378
Tier 3	$0.32721	$0.14748	$0.10370	$0.14781	$0.11132
Tier 4	$0.37114	$0.19141	$0.14763	$0.19174	$0.15525
Tier 5	$0.39125	$0.21152	$0.16774	$0.21185	$0.17536

* Includes baseline credit.

Note: EM, ES, ESR, and ET and their CARE counterparts use the E-1 and EL-1 rates shown above.

(END OF APPENDIX C)

APPENDIX D

SUPPLEMENTAL SMALL LIGHT AND POWER SETTLEMENT

SUPPLEMENTAL SMALL LIGHT AND POWER SETTLEMENT IN APPLICATION 04-06-024

I. SUPPLEMENTAL SMALL LIGHT AND POWER SETTLEMENT AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this settlement (Settling Parties) agree on a mutually acceptable outcome to issues regarding rates for Small Light and Power (SLP) customers in Application (A.) 04-06-024, 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 Application 04-06-024 filed in this proceeding on May 13, 2005 (May 13 Settlement), in that it uses the revenue allocation agreed to in the May 13 Settlement and addresses SLP issues that were not resolved in the May 13 Settlement. The Settling Parties intend that the complementary outcomes of this SLP Settlement and the May 13 Settlement be consolidated in the Commission's final decision in this proceeding.

II. SLP SETTLEMENT PARTIES

The Settling Parties are as follows:

California City-County Street Light Association (CAL-SLA)

Natural Resources Defense Council (NRDC)

Office of Ratepayer Advocates (ORA)

Pacific Gas and Electric Company (PG&E)

II. SLP SETTLEMENT CONDITIONS

The Settling Parties agree that this SLP Settlement resolves the specified issues raised in A.04-06-024 by the Settling Parties, subject to the following reservations:

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 May 13 Settlement and incorporates that agreement by reference. CAL-SLA, ORA, and PG&E are signatories to the May 13 Settlement. NRDC is not a signatory to the May 13 Settlement, since NRDC has taken no position on the issues covered by that agreement in this proceeding.

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, in accordance with Rule 51.1(e).

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 and actively support timely

Commission approval of this SLP Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 May 13 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 May 13 Settlement, the Settling Parties reserve their rights under Rule 51.7.

III. SLP SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

> On August 27, 2004, the *Scoping Memo And Ruling of Assigned Commissioner* (ACR) stated: "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding). ...

The three general subjects of the application are marginal costs, revenue allocation and rate design." The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 13, 2005, sixteen parties to this proceeding filed the May 13 Settlement regarding marginal cost and revenue allocation issues as well as Streetlight and Submetering rate design issues, and they stated that discussions would continue in an effort to reach agreement on the remaining rate design issues. The May 13 Settlement was filed before all rate design issues were resolved due to a June 1, 2005 deadline relating to a key feature of the May 13 Settlement.

After several discussions, on May 31, 2005, parties to the SLP rate design settlement discussions reached an agreement in principle, building from the SLP revenue allocation agreed to in the May 13 Settlement.

IV. SLP SETTLEMENT TERMS

1. Generally

The Settling Parties agree that the primary purpose of rate design for the SLP class is to take the revenue allocation reached for that class in the May 13 Settlement and ensure that it is fully recovered through SLP 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 rates set forth herein are consistent with the revenue allocation set forth in Table 2 of the May 13 Settlement Agreement, and that the actual rates calculated in accordance with this SLP Settlement may be somewhat different than those set forth below.

No later than June 9, 2005, PG&E will serve a comparison exhibit showing the impact of the SLP Settlement in relation to the litigation positions of PG&E and ORA, as required by Rule 51.1(c).

The Settling Parties agree that all testimony served prior to the date of this SLP Settlement that addresses the SLP rate design 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 will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.04-06-024. 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 SLP Settlement or the May 13 Settlement.

In terms of the 36 specific issues identified in Attachment A to the ACR and in subsequent ALJ rulings, this SLP Settlement resolves portions of Rate Design issues 3.6 and 3.10 (for the SLP customer class only).

2. A.04-06-024 SLP Rate Changes on January 1, 2006

The Settling Parties agree that rates to collect the revenue allocated to the SLP customer class under the May 13 Settlement on an overall revenue-neutral basis shall be designed as set forth below, and that these rates shall serve as the starting point for determining the changes to rates necessary to collect the adopted revenue requirement on January 1, 2006.

1. The customer charges for Schedules A-1 and A-6 shall be increased by 11 percent to $8.10 and $12.00 per month for single phase and poly phase service, respectively, restoring these charges to the levels at which they were set prior to the rate freeze. The customer charge for Schedules A-15 and TC-1 shall remain at their current level. The facilities charge for Schedule A-15 shall be increased to $15.00 per month.

2. Effective May 1, 2006, for Schedule A-6, Time of Use (TOU) processing and installation charges shall be eliminated. Ongoing TOU meter charges shall remain at their current levels.

3. The calculation of bills for commercial California Alternate Rates for Energy (CARE) customers shall remain unchanged and rely on a 20 percent discount based on the methodology specified in Schedule E-CARE.

4. The energy rates for the unbundled public purpose program, distribution and generation rate components for Schedule A-15 will be set equal to those calculated for Schedule A-1.

5. Effective May 1, 2006, Schedule E-36 shall be discontinued, and existing Schedule E-36 customers shall be transferred to service under Schedule A-1 or another applicable general service rate schedule..

6. The rates shown below are developed to collect the revenue allocated to the SLP class set forth in Table 2 (column 4) of the May 13 Settlement. Adopted revenue requirements shall be applied to these initial rates to determine rates effective in 2006. These rates are the best estimate of the rates that would be calculated based on actual Commission decisions at that time. However, the actual rates may be somewhat

Commission decisions at that time. However, the actual rates may be somewhat different than those shown below. Illustrative rates for Schedules TC-1, A-1, A-6 and A-15 are presented in Attachment A.

V. SLP 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.

This SLP Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

California City-County Street Light Association

By: Reed V. Schmidt

Title: CAL-SLA Energy Consultant

Natural Resources Defense Council

By: _____

Title: _____

Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

Commission decisions at that time. However, the actual rates may be somewhat different than those shown below. Illustrative rates for Schedules TC-1, A-1, A-6 and A-15 are presented in Attachment A.

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This SLP Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

California City-County Street Light Association

By: _____

Title: _____

Natural Resources Defense Council

By: Dana Baechnach

Title: Staff Scientist

Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

different than those shown below. Illustrative rates for Schedules TC-1, A-1, A-6 and A-15 are presented in Attachment A.

V. SLP SETTLEMENT EXECUTION

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This SLP Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

California City-County Street Light Association

By: _____

Title: _____

Natural Resources Defense Council

By: _____

Title: _____

Office of Ratepayer Advocates

By: [signature]

Title: Deputy Director

Pacific Gas and Electric Company

By: _____

Title: _____

different than those shown below. Illustrative rates for Schedules TC-1, A-1, A-6 and A-15 are presented in Attachment A.

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California City-County Street Light Association

By: _____

Title: _____

Natural Resources Defense Council

By: _____

Title: _____

Office of Ratepayer Advocates

By: _____

Title: _____

Pacific Gas and Electric Company

By: Adam L. Kwin

Title: Attorney

ATTACHMENT A

To Supplemental Small Light and Power
Settlement In Application 04-06-024

Illustrative January 1, 2006
Small Light and Power Rates

2003 GRC Ph2 Settlement
Small L&P Rate Design

	3/1/05 "Current" Total Rates	Settlement Based on GRC2 Rate Design Dist	Gen	Other	Total
A-1					
CUST CHARGE ($/MO.)					
Singlephase	$7.29	$8.10			$8.10
Polyphase	$10.80	$12.00			$12.00
ENERGY					
Summer	$0.18181	$0.05179	$0.06161	$0.03974	$0.15313
Winter	$0.12072	$0.03452	$0.04061	$0.03974	$0.11487
Avg Rates	$0.15042	$0.05086	$0.05151	$0.03973	$0.14210
		Percent Change from Current			-5.5%
A-6					
CUST CHARGE ($/MO.)					
Singlephase	$7.29	$8.10			$8.10
Polyphase	$10.80	$12.00			$12.00
METER CHARGE ($/MO.)	$6.12	$6.80			$6.80
ENERGY					
Summer					
Peak	$0.27233	$0.09954	$0.14308	$0.03843	$0.28104
Part-Peak	$0.12789	$0.03981	$0.06364	$0.03843	$0.14188
Off-Peak	$0.08123	$0.01991	$0.03030	$0.03843	$0.08863
Winter					
Part-Peak	$0.13915	$0.03281	$0.05463	$0.03843	$0.12586
Off-Peak	$0.09492	$0.02187	$0.03544	$0.03843	$0.09573
Avg Rates	$0.12390	$0.03638	$0.05223	$0.03843	$0.12703
		Percent Change from Current			2.5%
A-15					
CUST CHARGE ($/MO.)	$8.10	$8.10			$8.10
FACILITY CHARGE ($/MO.)	$7.80	$15.00			$15.00
ENERGY					
Summer	$0.23584	$0.05179	$0.06161	$0.03335	$0.14674
Winter	$0.18316	$0.03452	$0.04061	$0.03335	$0.10848
Avg Rates	$0.34293	$0.23700	$0.05111	$0.03335	$0.32146
		Percent Change from Current			-6.3%
TC-1					
CUST CHARGE ($/MO.)	$8.10	$8.10			$8.10
ENERGY					
Summer	$0.13076	$0.08024	$0.01877	$0.03114	$0.13015
Winter	$0.13076	$0.08024	$0.01877	$0.03114	$0.13015
Avg Rates	$0.15575	$0.10211	$0.01877	$0.03114	$0.15202
		Percent Change from Current			-2.4%

Notes:

(1) Gen and all other non-D rates from GRC showing
(2) D rates based on percent movement towards GRC proposed

(END OF APPENDIX D)

APPENDIX E

SUPPLEMENTAL LIGHT AND POWER SETTLEMENT

SUPPLEMENTAL LIGHT AND POWER SETTLEMENT

IN APPLICATION 04-06-024

I. SUPPLEMENTAL LIGHT AND POWER SETTLEMENT AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this settlement (Settling Parties) agree on a mutually acceptable outcome to issues regarding rates for Light and Power (L&P) customers, encompassing the Medium and Large Light and Power and Standby Service customer classes, in Application (A.) 04-06-024, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This L&P Settlement is supplemental to the Settlement In Application 04-06-024 filed in this proceeding on May 13, 2005 (May 13 Settlement), in that it uses the revenue allocation agreed to in the May 13 Settlement and addresses L&P issues that were not resolved in the May 13 Settlement. The Settling Parties intend that the complementary outcomes of this L&P Settlement and the May 13 Settlement be consolidated in the Commission's final decision in this proceeding.

II. L&P SETTLEMENT PARTIES

The Settling Parties are as follows:

Building Owners and Managers Associations of San Francisco and California (BOMA)

California Large Energy Consumers Association (CLECA)

California Manufacturers & Technology Association (CMTA)

Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC)

East Bay Municipal Utility District (EBMUD)

Energy Users Forum (EUF)

Indicated Commercial Parties (ICP)

Pacific Gas and Electric Company (PG&E)

Wal-Mart Stores, Inc. (Wal-Mart)

III. L&P SETTLEMENT CONDITIONS

The Settling Parties agree that this L&P Settlement resolves the specified issues raised in A.04-06-024 by the Settling Parties, subject to the following reservations:

1. This L&P 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 L&P Settlement builds on the revenue allocation in the May 13 Settlement and incorporates that agreement by reference. All nine Settling Parties (BOMA, CLECA, CMTA, CAC/EPUC, ICP, EBMUD, EUF, PG&E, and Wal-Mart) are signatories to the May 13 Settlement.

2. This L&P Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts, legal arguments or policy recommendations presented by the Settling Parties in this proceeding. This L&P 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 L&P Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest, in accordance with Rule 51.1(e).

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

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

6. The Settling Parties shall jointly request and actively support timely Commission approval of this L&P Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 L&P Settlement to be interpreted and treated as a unified, integrated agreement incorporating the May 13 Settlement which forms the foundation for the L&P rate design agreed to herein. In the event the Commission rejects or modifies this L&P Settlement or the underlying May 13 Settlement, the Settling Parties reserve their rights under Rule 51.7.

IV. L&P SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

On August 27, 2004, the Scoping Memo And Ruling of Assigned Commissioner (ACR) stated:

> "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding) ... The three general subjects of the application are marginal costs, revenue allocation and rate design."

The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 13, 2005, sixteen parties to this proceeding filed the May 13 Settlement regarding marginal cost and revenue allocation issues as well as Streetlight and Submetering rate design issues, and they stated that discussions would continue in an effort to reach agreement on the remaining rate design issues. The May 13 Settlement was filed before all rate design issues were resolved due to a June 1, 2005 deadline relating to a key feature of the May 13 Settlement.

On June 3, 2005, three parties to this proceeding filed the Supplemental Residential Settlement In Application 04-06-024, and four parties to this proceeding filed the Supplemental Small Light and Power Settlement In Application 04-06-024.

After several discussions, on July 5, 2005, the nine parties to the L&P rate design settlement discussions reached an agreement in principle, building from the L&P customer class revenue allocations agreed to in the May 13 Settlement.

V. L&P SETTLEMENT TERMS

1. Generally

The Settling Parties agree that the primary purpose of rate design for the L&P classes is to take the revenue allocations reached for these classes in the May 13 Settlement and ensure that they are fully recovered through L&P 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 rates set forth herein are consistent with the revenue allocation set forth in Table 2 of the May 13 Settlement Agreement, and understand that the actual rates calculated in accordance with this L&P Settlement may be somewhat different than those set forth below.

The Settling Parties agree that all testimony served prior to the date of this L&P Settlement that addresses the L&P rate design issues resolved by this L&P Settlement should be admitted into evidence without cross-examination by the Settling Parties. This L&P Settlement resolves all outstanding Phase 2 issues for the L&P customer classes.

In terms of the 36 specific issues identified in Attachment A to the ACR and in subsequent ALJ rulings, this L&P Settlement resolves portions of Rate Design issues 3.6 (for the L&P customer classes only) and 3.10.

2. A.04-06-024 L&P Rate Changes on January 1, 2006

The Settling Parties agree that rates to collect the revenue allocated to the L&P customer classes under the May 13 Settlement on an overall revenue-neutral basis shall be designed as set forth below, and that these rates shall serve as the starting point for determining the changes to rates necessary to collect the adopted revenue requirement on January 1, 2006.

Illustrative rates for the Light and Power Rate Schedules are presented in Attachment A. The rates were developed to collect the revenue allocated to the L&P customer classes set forth in Table 2 (column 4) of the May 13 Settlement. Adopted revenue requirements shall be applied to these initial rates to determine rates effective in 2006. These rates are the best estimate of the rates that would be calculated based on actual Commission decisions at that time. However, the actual rates may be somewhat different than those shown in Attachment A. The tables provided in Attachment A include comparisons of PG&E's litigation positions with the outcome for the L&P Settlement. (This comparison meets Rule 51.1(c) requirements, because ORA did not take a position on rates for the L&P rate schedules.)

3. Methods Used To Develop Illustrative January 1, 2006 Rates

The Settling Parties agree that the basic rate designs for each of the applicable L&P rate schedules will be updated using the methods proposed by PG&E in its most current updated testimony, Exhibit (PG&E-11), Supplemental Testimony Updating Revenue Allocation and Rate Design for 2006 Test Year Sales, filed May 3, 2005, except for certain modifications that have been agreed upon to mitigate changes from existing rate design relationships under Schedules E-19 and E-20. Specifically, the Settling Parties agree that it is reasonable to limit any increases to the Distribution

component of maximum demand charges applicable for service under these two rate schedules to one-half of the total increase that would otherwise result from PG&E's proposed rate design methods. The resulting maximum demand charge revenue under-collections are then assigned instead to the corresponding time-of-use (TOU) demand charges for each rate schedule.

4. Implement 15-Minute Demand Charge Intervals

The Settling Parties agree that it is reasonable to change from 30 minute to 15 minute demand charge intervals for service under Schedules E-19 and E-20 and for those Schedule A-10 and E-19V customers with demands above 400 kW. This change will ensure that common 15-minute demand intervals are applicable for all Schedule A-10, E-19 and E-20 customers. The Settling Parties further agree that it is reasonable for this billing change to become effective for all affected customers on May 1, 2006.

5. Adopt Revised Customer Charges

The Settling Parties agree that PG&E's proposed customer charges for the L&P rate schedules are reasonable.

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

The Settling Parties agree that it is reasonable to eliminate summer season on-peak 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 distribution voltages, at the revised levels set forth in Appendix A. 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 those provided by the current average rate limiters (which apply only to the portion of the bill that is attributable to "rate freeze" period rates). The

Settling Parties understand that, consistent with past practice, the final rates implemented on January 1, 2006 should incorporate adjustments to account for estimated undercollections associated with the average rate limiter.

7. Eliminate Optimal Billing Program

The Settling Parties agree that it is reasonable to eliminate the Optimal Billing Program, which was a rate option that allowed certain qualifying Schedule E-19 and E-20 customers engaged in food processing activities to re-designate certain meter read dates at the beginning and end of their peak processing seasons, with this billing change to become effective for affected customers on May 1, 2006.

8. Discontinue Schedule E-25

The Settling Parties agree that it is reasonable to eliminate this short-peak-period TOU rate option for qualifying water agency customers who would otherwise take service under Schedule E-19 or E-20. This billing change, which will affect fewer than ten customers, would become effective on May 1, 2006.

9. Revise Power Factor Adjustments

The Settling Parties agree that it is reasonable to convert the current power factor adjustment rates applicable under the L&P rate schedules on a revenue-neutral basis, from a percent of billed revenues basis to a per kilowatt-hour (kWh) basis. This billing change, which will make it possible to apply power factor adjustments on a uniform basis for both direct access and bundled service customers and eliminates the need to use historic "rate freeze" period rates (which are used for the current power factor adjustments), would become effective beginning May 1, 2006.

10. Eliminate TOU Meter Installation Charges

The Settling Parties agree that it is reasonable to eliminate TOU Installation and

TOU Processing charges for customers with demands of less than 500 kW electing to take voluntary TOU service under Schedule E-19. This billing change would become effective beginning on May 1, 2006.

11. Remove Energy Efficiency Eligibility Clause From Schedule E-20

The Settling Parties agree that it is reasonable to remove the "Energy Efficiency Adjustment" clause from the Schedule E-20 tariff, which was first established over 15 years ago and provided a way of maintaining eligibility for service under Schedule E-20 for a limited number of customers who would otherwise be served on Schedule E-19.

12. Adopt Updated Standby Service Rates

The Settling Parties agree that PG&E's proposed methods for setting standby service rates are reasonable (for those components of the standby service rates that are subject to CPUC jurisdiction), with the understanding 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 recognize that the class-level revenue allocations that were determined by the May 13 Settlement preclude implementing distribution-voltage standby rates that might fully "allocate distribution capacity costs to Schedule S on the same basis as if no customer generation were installed." (See Exhibit (PG&E-4) at page 6-9 for further discussion.) The Settling Parties agree that it is reasonable to defer further consideration of this issue to Phase 2 of PG&E's 2007 GRC.

13. Adopt New Physical Assurance Contract for Distributed Generation Customers Taking Service Under Schedule S

The Settling Parties agree that PG&E's proposed standard form contract for Physical Assurance, as presented in Appendix C to Exhibit (PG&E-4)), is reasonable

and meets the requirements for such agreements as specified in D.01-07-027 from the Distributed Generation rulemaking (R.99-10-025). Billing changes associated with the new Physical Assurance agreements should become effective May 1, 2006.

14. Eliminate Non-Firm Rate Option Under Schedule S

The Settling Parties do not oppose using the new Physical Assurance Agreement as a substitute for establishing separate non-firm service rates for standby customers. (No customers would be affected by eliminating the existing provisions for non-firm standby service, because no Schedule S customer has ever elected this service option.)

15. One-Year Ratchet Period for Standby Contract Demand

The Settling Parties agree that PG&E's proposed reduction of the standard ratchet period for standby service reservation capacity elected under Schedule S, from 36 months to 12 months, is reasonable and meets the requirements of D.01-07-027. Billing changes associated with the reduced ratchet period should become effective May 1, 2006.

16. Provisions Related to Standard Non-Firm Service Rates

All parties to the May 13, 2005 Settlement have already agreed that the incentives for service under the standard non-firm rate program should be retained at the same absolute level of demand and energy charge credits as are currently in effect for service under Schedules E-19 and E-20. This provision would remain in effect until the Commission reviews this issue in Phase 2 of PG&E's next General Rate Case, or until the Commission separately considers non-firm issues in another forum, such as the statewide Critical Peak Pricing proceeding (A.05-01-016 et al.).

The Settling Parties agree that it is reasonable for PG&E, at the time that rates are implemented pursuant to a decision in A.04-06-024, to restate the existing non-firm

program terms and conditions and corresponding rate credits in the form of a separate, supplementary rate schedule. The supplementary non-firm service rate schedule would then apply as a rider to each participant's otherwise applicable charges under Schedule E-19 or E-20.

17. Provisions Relating To Non-Firm Rate Eligibility

The Settling Parties agree that the current eligibility provisions for the non-firm tariff should be modified in order to restore eligibility for a small number of customers who have previously taken non-firm service but have lost their eligibility as a result of corporate ownership changes. The revised eligibility provision would read as follows:

> In accordance with Decision 01-04-006, the Non-Firm Service Program is closed to new customers and existing customers that are not currently in the program. However, existing customers adding new load can qualify that new load for this Schedule as long as minimal load reduction conditions are met. Customers newly taking service from PG&E can take service under this Schedule for: (a) loads not previously served by PG&E, or (b) *loads that were previously served under PG&E's "Supplemental Agreement for Optional Non-Firm Electric Service (Form 79-724) or "Supplemental Agreement for Optional Curtailable and Interruptible Electric Service" (Form 79-724A), on or after January 1, 2003.*

PG&E believes that no more than five customers with a total load of no more than about 10 to 15 MW would have their eligibility for standard non-firm service restored by this tariff modification.

18. Provisions Relating To Service Under Schedule E-BIP

The Settling Parties agree that Schedule E-BIP (the tariff for PG&E's "Base Interruptible Program," which the Commission has established as an alternative to the standard interruptible tariffs) should be modified to include an Underfrequency Relay (UFR) service option comparable to the UFR rate option that has long been offered under PG&E's standard non-firm tariffs. Non-firm service customers who elect to

participate in the UFR program agree to make their loads available for complete and automatic interruption in the event of certain system disturbances. In exchange, these customers receive a modest additional rate incentive of $8.00 per kW per year, with this value having been established some years ago by D.92-05-031. The Commission has established a goal of eventually moving non-firm rate program customers to service under Schedule E-BIP, with the understanding that Schedule E-BIP offers incentives that are meant to be comparable to those available under the original non-firm tariffs. PG&E believes and the Settling Parties understand that many UFR-option customers would be harmed by such a transfer to the extent that comparable UFR incentives are not available under Schedule E-BIP. Therefore, the Settling Parties believe that it is reasonable to add an additional demand credit of $0.67 per kW per month to Schedule E-BIP for those customers who would prefer to continue UFR service.

19. Defer Consideration of Account Aggregation Proposals To Phase 2 of PG&E's 2007 General Rate Case

The Settling Parties agree that it is reasonable to defer further consideration of account aggregation proposals to Phase 2 of PG&E's 2007 GRC. PG&E will provide the staff and other resources necessary to design and perform a study examining the implications of agricultural and water agency pumping load account aggregation in anticipation of its Phase 2 filing. This analysis is intended as a follow-up study to PG&E's earlier Assembly Bill 1421 Report. The study framework, methodology, and implementation will be developed through mutual agreement between PG&E, EBMUD, the Agricultural Energy Consumers Association, and the California Farm Bureau Federation.

VI. L&P 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 L&P Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the L&P Settlement as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this L&P Settlement on behalf of the Settling Parties they represent.

This L&P Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Building Owners and Managers Associations of San Francisco and California

By: _____
Bill F. Roberts
Title: President, Economic Sciences Corp.

California Large Energy Consumers Association

By: _____

Title: _____

California Manufacturers & Technology Association

By: _____

Title: _____

VI. L&P SETTLEMENT EXECUTION

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This L&P Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Building Owners and Managers Associations of San Francisco and California

By: _____

Title: _____

California Large Energy Consumers Association

By: W H Booth

Title: Attorney

California Manufacturers & Technology Association

By: _____

Title: _____

VI. L&P 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 L&P Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the L&P Settlement as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this L&P Settlement on behalf of the Settling Parties they represent.

This L&P Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Building Owners and Managers Associations of San Francisco and California

By: _____

Title: _____

California Large Energy Consumers Association

By: _____

Title: _____

California Manufacturers & Technology Association

By: Keith R McCrea

Title: Attorney

Cogeneration Association of California and Energy Producers and Users Coalition

By: [illegible]

Title: Counsel

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

Indicated Commercial Parties

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: [illegible]

Title: Manager of Water System

Energy Users Forum

By: _____

Title: _____

Indicated Commercial Parties

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

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Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: [signature]

Title: Principal

Indicated Commercial Parties

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

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Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

Indicated Commercial Parties

By: Randall W. Keen
Manatt, Phelps & Phillips, LLP, Attorneys for
Title: Indicated Commercial Parties

Pacific Gas and Electric Company

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

Indicated Commercial Parties

By: _____

Title: _____

Pacific Gas and Electric Company

By: Andrew L. Niven

Title: Attorney

Wal-Mart Stores, Inc.

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

East Bay Municipal Utility District

By: _____

Title: _____

Energy Users Forum

By: _____

Title: _____

Indicated Commercial Parties

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

Wal-Mart Stores, Inc.

By: G Klatt

Title: Counsel of Record

ATTACHMENT A

To Supplemental Light and Power
Settlement in Application 04-06-024

SCHEDULE E-20

		Total Rates Eff. 3/1/05	RDSA Methodology - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC Phase 2 Settlement Rates Dist	Gen	Other	Total	GRC2 Methods - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC2 Supp. Testimony (2006 Sales) Dist	Gen	Other	Total
							Max demand charge % to GRC:			50%								
CUST CHARGE ($/MO.)																		
Secondary		$385	$385			$385	$600			$600	$600			$600	$600			$600
Primary		$310	$310			$310	$800			$800	$800			$800	$800			$800
Transmission		$715	$715			$715	$1,500			$1,500	$1,500			$1,500	$1,500			$1,500
DEMAND ($/kW)																		
Secondary	Smr Pk	$13.42	$6.15	$6.17		$12.32	$6.28	$5.93		$12.22	$4.39	$5.93		$10.33	$2.25	$6.39		$8.64
	Smr Pt-Pk	$3.73	$1.72	$1.71		$3.43	$1.60	$1.20		$2.80	$1.12	$1.20		$2.32	$0.57	$1.29		$1.86
	Smr Max	$3.27	$2.22	-$4.05	$4.62	$2.79	$3.68		$4.62	$8.30	$5.15		$4.62	$9.77	$2.64		$4.62	$7.26
	Wtr Pt-Pk	$3.67	$1.69	$1.67		$3.37	$1.85			$1.85	$1.30			$1.30	$0.67			$0.67
	Wtr Max	$3.27	$2.22	-$4.05	$4.62	$2.79	$3.68		$4.62	$8.30	$5.15		$4.62	$9.77	$2.64		$4.62	$7.26
Primary	Smr Pk	$11.65	$3.03	$7.09		$10.12	$2.57	$6.50		$9.07	$1.84	$6.50		$8.34	$1.75	$6.64		$8.39
	Smr Pt-Pk	$2.62	$0.70	$1.58		$2.28	$0.70	$1.41		$2.10	$0.50	$1.41		$1.91	$0.47	$1.44		$1.91
	Smr Max	$3.24	$1.13	-$2.90	$4.62	$2.85	$1.69		$4.62	$6.31	$2.25		$4.62	$6.87	$2.14		$4.62	$6.76
	Wtr Pt-Pk	$2.62	$0.70	$1.58		$2.28	$0.72			$0.72	$0.52			$0.52	$0.49			$0.49
	Wtr Max	$3.24	$1.13	-$2.90	$4.62	$2.85	$1.69		$4.62	$6.31	$2.25		$4.62	$6.87	$2.14		$4.62	$6.76
Transmission	Smr Pk	$7.27	$0.00	$6.03		$6.03		$6.98		$6.98		$6.98		$6.98		$7.64		$7.64
	Smr Pt-Pk	$0.58	$0.00	$0.48		$0.48		$1.52		$1.52		$1.52		$1.52		$1.66		$1.66
	Smr Max	$0.95	$0.00	-$4.24	$4.62	$0.38			$4.62	$4.62			$4.62	$4.62	$0.32		$4.62	$4.94
	Wtr Pt-Pk	$0.73	$0.00	$0.60		$0.60				$0.00				$0.00				$0.00
	Wtr Max	$0.95	$0.00	-$4.24	$4.62	$0.38			$4.62	$4.62			$4.62	$4.62	$0.32		$4.62	$4.94
ENERGY ($/kWh)																		
Secondary	Smr Pk	$0.15410	$0.01454	$0.10202	$0.01724	$0.13379	$0.01413	$0.07469	$0.01724	$0.10605	$0.01413	$0.07469	$0.01724	$0.10605	$0.00725	$0.08041	$0.02068	$0.10834
	Smr Pt-Pk	$0.08718	$0.00963	$0.05001	$0.01724	$0.07688	$0.00565	$0.05503	$0.01724	$0.07792	$0.00565	$0.05503	$0.01724	$0.07792	$0.00290	$0.05924	$0.02068	$0.08282
	Smr Off-Pk	$0.07986	$0.00839	$0.04488	$0.01724	$0.07051	$0.00283	$0.03711	$0.01724	$0.05717	$0.00283	$0.03711	$0.01724	$0.05717	$0.00145	$0.03995	$0.02068	$0.06208
	Wtr Pt-Pk	$0.09283	$0.01058	$0.05398	$0.01724	$0.08180	$0.00492	$0.04994	$0.01724	$0.07209	$0.00492	$0.04994	$0.01724	$0.07209	$0.00252	$0.05376	$0.02068	$0.07696
	Wtr Off-Pk	$0.07966	$0.00836	$0.04473	$0.01724	$0.07033	$0.00328	$0.03918	$0.01724	$0.05970	$0.00328	$0.03918	$0.01724	$0.05970	$0.00168	$0.04218	$0.02068	$0.06454
Primary	Smr Pk	$0.12706	$0.00439	$0.08705	$0.01628	$0.10772	$0.00593	$0.07637	$0.01628	$0.09858	$0.00593	$0.07637	$0.01628	$0.09858	$0.00564	$0.07796	$0.01954	$0.10314
	Smr Pt-Pk	$0.07703	$0.00343	$0.04660	$0.01628	$0.06631	$0.00237	$0.05620	$0.01628	$0.07485	$0.00237	$0.05620	$0.01628	$0.07485	$0.00226	$0.05737	$0.01954	$0.07917
	Smr Off-Pk	$0.07523	$0.00330	$0.04521	$0.01628	$0.06479	$0.00119	$0.03805	$0.01628	$0.05552	$0.00119	$0.03805	$0.01628	$0.05552	$0.00113	$0.03885	$0.01954	$0.05952
	Wtr Pt-Pk	$0.08482	$0.00400	$0.05257	$0.01628	$0.07285	$0.00200	$0.04991	$0.01628	$0.06818	$0.00200	$0.04991	$0.01628	$0.06818	$0.00190	$0.05095	$0.01954	$0.07239
	Wtr Off-Pk	$0.07602	$0.00335	$0.04583	$0.01628	$0.06546	$0.00133	$0.04013	$0.01628	$0.05774	$0.00133	$0.04013	$0.01628	$0.05774	$0.00127	$0.04096	$0.01954	$0.06177
Transmission	Smr Pk	$0.11838	$0.00035	$0.08576	$0.01519	$0.10129	$0.00000	$0.05146	$0.01519	$0.06665		$0.05146	$0.01519	$0.06665		$0.05635	$0.01832	$0.07467
	Smr Pt-Pk	$0.07101	$0.00023	$0.04601	$0.01519	$0.06143	$0.00000	$0.04603	$0.01519	$0.06122		$0.04603	$0.01519	$0.06122		$0.05040	$0.01832	$0.06872
	Smr Off-Pk	$0.06844	$0.00023	$0.04386	$0.01519	$0.05927	$0.00000	$0.03344	$0.01519	$0.04862		$0.03344	$0.01519	$0.04862		$0.03661	$0.01832	$0.05493
	Wtr Pt-Pk	$0.08077	$0.00023	$0.05421	$0.01519	$0.06963	$0.00000	$0.04376	$0.01519	$0.05894		$0.04376	$0.01519	$0.05894		$0.04791	$0.01832	$0.06623
	Wtr Off-Pk	$0.07158	$0.00023	$0.04649	$0.01519	$0.06190	$0.00000	$0.03530	$0.01519	$0.05048		$0.03530	$0.01519	$0.05048		$0.03865	$0.01832	$0.05697
AVG RATE LIMITER																		
Secondary		$0.13995		Applies to rate freeze		$0.13995		This cap is applied to		$0.17788				N/A				N/A
Primary		$0.13995		portion of total bill only		$0.13995		total of all applicable		$0.17788				N/A				N/A
Transmission		-				-		kW & kWh charges		N/A				N/A				N/A
PEAK RATE LIMITER																		
Secondary		$0.97708				$0.97708				N/A				N/A				N/A
Primary		$0.84876				$0.84876				N/A				N/A				N/A
Transmission		$0.55750				$0.55750				N/A				N/A				N/A
Avg Rates																		
Secondary		$0.12528	$0.02678	$0.05610	$0.02856	$0.11145	$0.02716	$0.05607	$0.02856	$0.11180	$0.02716	$0.05607	$0.02856	$0.11180	$0.01410	$0.06037	$0.03201	$0.10648
Primary		$0.10905	$0.01120	$0.05633	$0.02691	$0.09444	$0.01140	$0.05625	$0.02691	$0.09456	$0.01140	$0.05625	$0.02691	$0.09456	$0.01050	$0.05743	$0.03017	$0.09811
Transmission		$0.08878	$0.00057	$0.04929	$0.02575	$0.07561	$0.00066	$0.04855	$0.02575	$0.07495	$0.00066	$0.04855	$0.02575	$0.07495	$0.00122	$0.05317	$0.02888	$0.08327

SCHEDULE E-19		Total Rates Eff. 3/1/05 non-FTA	RDSA Methodology - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC Phase 2 Settlement Rates Dist	Gen	Other	Total	GRC2 Methods - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC2 Supp. Testimony (2006 Sales) Dist	Gen	Other	Total
							Max demand charge % to GRC:			50%								
METER CHARGE ($/MO.) (< 500 kW, all voltages)		$6.00	$6.00			$6.00	$6.00			$6.00	$7.90			$7.90	$7.90			$7.90
CUST CHARGE ($/MO.)																		
Voluntary (all voltages)		$75	$75			$75	$100			$100	$100			$100	$100			$100
Secondary		$175	$175			$175	$275			$275	$275			$275	$275			$275
Primary		$140	$140			$140	$400			$400	$400			$400	$400			$400
Transmission		$610	$610			$610	$1,200			$1,200	$1,200			$1,200	$1,200			$1,200
DEMAND ($/kW)																		
Secondary	Smr Pk	$13.51	$7.06	$5.51		$12.57	$5.71	$6.19		$11.90	$3.95	$6.19		$10.15	$2.59	$6.29		$8.88
	Smr Pt-Pk	$3.75	$1.97	$1.52		$3.49	$1.54	$1.33		$2.87	$1.07	$1.33		$2.39	$0.70	$1.35		$2.05
	Smr Max	$3.18	$2.01	-$3.62	$4.34	$2.73	$3.37		$4.34	$7.71	$4.73		$4.34	$9.07	$3.10		$4.34	$7.44
	Wtr Pt-Pk	$3.69	$1.93	$1.51		$3.44	$1.65			$1.65	$1.14			$1.14	$0.75			$0.75
	Wtr Max	$3.18	$2.02	-$3.63	$4.34	$2.73	$3.37		$4.34	$7.71	$4.73		$4.34	$9.07	$3.10		$4.34	$7.44
Primary	Smr Pk	$11.74	$4.02	$6.37		$10.39	$2.38	$5.73		$8.11	$1.77	$5.73		$7.51	$1.87	$5.57		$7.44
	Smr Pt-Pk	$2.64	$0.89	$1.44		$2.33	$0.64	$1.24		$1.88	$0.48	$1.24		$1.72	$0.51	$1.20		$1.71
	Smr Max	$3.15	$1.18	-$2.73	$4.34	$2.79	$1.64		$4.34	$5.98	$2.10		$4.34	$6.44	$2.22		$4.34	$6.56
	Wtr Pt-Pk	$2.64	$0.89	$1.44		$2.33	$0.69			$0.69	$0.52			$0.52	$0.55			$0.55
	Wtr Max	$3.15	$1.18	-$2.73	$4.34	$2.79	$1.64		$4.34	$5.98	$2.10		$4.34	$6.44	$2.22		$4.34	$6.56
Transmission	Smr Pk	$7.26	$0.00	$5.96		$5.96		$7.71		$7.71		$7.71		$7.71		$7.11		$7.11
	Smr Pt-Pk	$0.58	$0.00	$0.48		$0.48		$1.78		$1.78		$1.78		$1.78		$1.64		$1.64
	Smr Max	$0.87	$0.09	-$4.10	$4.34	$0.33			$4.34	$4.34	$2.55		$4.34	$6.89	$2.33		$4.34	$6.67
	Wtr Pt-Pk	$0.73	$0.00	$0.60		$0.60				$0.00				$0.00				$0.00
	Wtr Max	$0.87	$0.09	-$4.10	$4.34	$0.33			$4.34	$4.34	$2.55		$4.34	$6.89	$2.33		$4.34	$6.67
ENERGY ($/kWh)																		
Secondary	Smr Pk	$0.15657	$0.00961	$0.10717	$0.01752	$0.13429	$0.01320	$0.08078	$0.01752	$0.11149	$0.01320	$0.08078	$0.01752	$0.11149	$0.00866	$0.08207	$0.02100	$0.11173
	Smr Pt-Pk	$0.09524	$0.00635	$0.05878	$0.01752	$0.08265	$0.00528	$0.05934	$0.01752	$0.08214	$0.00528	$0.05934	$0.01752	$0.08214	$0.00346	$0.06029	$0.02100	$0.08475
	Smr Off-Pk	$0.08134	$0.00554	$0.04789	$0.01752	$0.07094	$0.00264	$0.03998	$0.01752	$0.06013	$0.00264	$0.03998	$0.01752	$0.06013	$0.00173	$0.04062	$0.02100	$0.06335
	Wtr Pt-Pk	$0.10092	$0.00699	$0.06300	$0.01752	$0.08751	$0.00455	$0.05379	$0.01752	$0.07586	$0.00455	$0.05379	$0.01752	$0.07586	$0.00298	$0.05465	$0.02100	$0.07863
	Wtr Off-Pk	$0.08114	$0.00551	$0.04774	$0.01752	$0.07076	$0.00304	$0.04221	$0.01752	$0.06276	$0.00304	$0.04221	$0.01752	$0.06276	$0.00199	$0.04288	$0.02100	$0.06587
Primary	Smr Pk	$0.13071	$0.00303	$0.09059	$0.01713	$0.11075	$0.00654	$0.08050	$0.01713	$0.10417	$0.00654	$0.08050	$0.01713	$0.10417	$0.00692	$0.07822	$0.02061	$0.10575
	Smr Pt-Pk	$0.08484	$0.00235	$0.05327	$0.01713	$0.07275	$0.00262	$0.05963	$0.01713	$0.07937	$0.00262	$0.05963	$0.01713	$0.07937	$0.00277	$0.05794	$0.02061	$0.08132
	Smr Off-Pk	$0.07669	$0.00228	$0.04660	$0.01713	$0.06601	$0.00131	$0.04047	$0.01713	$0.05891	$0.00131	$0.04047	$0.01713	$0.05891	$0.00138	$0.03933	$0.02061	$0.06132
	Wtr Pt-Pk	$0.09292	$0.00276	$0.05961	$0.01713	$0.07950	$0.00223	$0.05308	$0.01713	$0.07244	$0.00223	$0.05308	$0.01713	$0.07244	$0.00236	$0.05158	$0.02061	$0.07455
	Wtr Off-Pk	$0.07765	$0.00230	$0.04738	$0.01713	$0.06680	$0.00149	$0.04268	$0.01713	$0.06129	$0.00149	$0.04268	$0.01713	$0.06129	$0.00157	$0.04147	$0.02061	$0.06365
Transmission	Smr Pk	$0.14229	$0.00997	$0.09587	$0.01727	$0.12311	$0.00000	$0.06377	$0.01727	$0.08104		$0.06377	$0.01727	$0.08104		$0.05879	$0.02075	$0.07954
	Smr Pt-Pk	$0.09720	$0.00756	$0.06008	$0.01727	$0.08491	$0.00000	$0.05705	$0.01727	$0.07431		$0.05705	$0.01727	$0.07431		$0.05259	$0.02075	$0.07334
	Smr Off-Pk	$0.08809	$0.00710	$0.05284	$0.01727	$0.07720	$0.00000	$0.04144	$0.01727	$0.05871		$0.04144	$0.01727	$0.05871		$0.03820	$0.02075	$0.05895
	Wtr Pt-Pk	$0.11222	$0.00933	$0.07126	$0.01727	$0.09785	$0.00000	$0.05423	$0.01727	$0.07149		$0.05423	$0.01727	$0.07149		$0.04999	$0.02075	$0.07074
	Wtr Off-Pk	$0.09297	$0.00767	$0.05647	$0.01727	$0.08141	$0.00000	$0.04374	$0.01727	$0.06101		$0.04374	$0.01727	$0.06101		$0.04032	$0.02075	$0.06107
AVG RATE LIMITER																		
Secondary		$0.14043		Applies to rate freeze		$0.14043		This cap is applied to		$0.17841				N/A				N/A
Primary		$0.14043		portion of total bill only		$0.14043		total of all applicable		$0.17841				N/A				N/A
Transmission		-				-		kW & kWh charges		N/A				N/A				N/A
PEAK RATE LIMITER																		
Secondary		$0.97773				$0.97773				N/A				N/A				N/A
Primary		$0.84937				$0.84937				N/A				N/A				N/A
Transmission		$0.58676				$0.58676				N/A				N/A				N/A
Avg Rates																		
Secondary		$0.12971	$0.02591	$0.06017	$0.02853	$0.11461	$0.02622	$0.06016	$0.02853	$0.11491	$0.02622	$0.06016	$0.02853	$0.11491	$0.01694	$0.06113	$0.03188	$0.10995
Primary		$0.11798	$0.01319	$0.06002	$0.02919	$0.10240	$0.01342	$0.06005	$0.02919	$0.10265	$0.01342	$0.06005	$0.02919	$0.10265	$0.01357	$0.05835	$0.03239	$0.10431
Transmission		$0.11605	$0.01067	$0.06127	$0.02819	$0.10014	$0.01049	$0.06071	$0.02819	$0.09939	$0.01049	$0.06071	$0.02819	$0.09939	$0.00959	$0.05596	$0.03194	$0.09749

SCHEDULE A-10		Total Rates Eff. 3/1/05 non-FTA	RDSA Methodology - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC Phase 2 Settlement Rates Dist	Gen	Other	Total	GRC2 Methods - Ph 2 Settlement RRQs Dist	Gen	Other	Total	GRC2 Supp. Testimony (2006 Sales) Dist	Gen	Other	Total
CUST CHARGE ($/MO.)		$75.00	$75.00			$75.00	$100.00			$100.00	$100.00			$100.00	$100.00			$100.00
DEMAND ($/kW)																		
Secondary	Smr Max	$7.60	$5.58	-$2.38	$4.34	$7.54	$3.09	$2.95	$4.34	$10.39	$3.09	$2.95	$4.34	$10.39	$2.47	$2.96	$4.34	$9.77
	Wtr Max	$2.25	$1.38	-$3.99	$4.34	$1.73	$2.06	$0.00	$4.34	$6.40	$2.06		$4.34	$6.40	$1.64		$4.34	$5.98
Primary	Smr Max	$6.29	$3.88	-$2.06	$4.34	$6.16	$2.34	$3.18	$4.34	$9.86	$2.34	$3.18	$4.34	$9.86	$1.63	$2.95	$4.34	$8.92
	Wtr Max	$2.23	$1.15	-$3.79	$4.34	$1.71	$1.65	$0.00	$4.34	$5.99	$1.65		$4.34	$5.99	$1.15		$4.34	$5.49
Transmission	Smr Max	$2.51	$0.00	-$2.15	$4.34	$2.19	$0.00	$2.91	$4.34	$7.25	$0.00	$2.91	$4.34	$7.25	$0.06	$2.34	$4.34	$6.74
	Wtr Max	$0.96	$0.00	-$3.99	$4.34	$0.35	$0.00	$0.00	$4.34	$4.34	$0.00		$4.34	$4.34	$0.05		$4.34	$4.39
ENERGY ($/kWh)																		
Secondary	Smr	$0.14036	$0.01213	$0.09102	$0.01876	$0.12191	$0.01551	$0.06836	$0.01876	$0.10263	$0.01551	$0.06836	$0.01876	$0.10263	$0.01237	$0.06857	$0.02258	$0.10352
	Wtr	$0.10277	$0.00989	$0.06145	$0.01876	$0.09009	$0.01034	$0.05068	$0.01876	$0.07978	$0.01034	$0.05068	$0.01876	$0.07978	$0.00825	$0.05083	$0.02258	$0.08166
Primary	Smr	$0.14148	$0.00939	$0.09372	$0.01856	$0.12167	$0.01177	$0.07217	$0.01856	$0.10249	$0.01177	$0.07217	$0.01856	$0.10249	$0.00817	$0.06701	$0.02238	$0.09756
	Wtr	$0.10125	$0.00765	$0.06176	$0.01856	$0.08796	$0.00784	$0.05279	$0.01856	$0.07918	$0.00784	$0.05279	$0.01856	$0.07918	$0.00545	$0.04901	$0.02238	$0.07684
Transmission	Smr	$0.13044	$0.00051	$0.09176	$0.01847	$0.11073	$0.00001	$0.07638	$0.01847	$0.09485	$0.00001	$0.07638	$0.01847	$0.09485	$0.00036	$0.06146	$0.02229	$0.08411
	Wtr	$0.10801	$0.00040	$0.07323	$0.01847	$0.09209	$0.00001	$0.05645	$0.01847	$0.07492	$0.00001	$0.05645	$0.01847	$0.07492	$0.00024	$0.04543	$0.02229	$0.06796
Avg Rates																		
Secondary		$0.14282	$0.02687	$0.06511	$0.03346	$0.12545	$0.02687	$0.06511	$0.03346	$0.12544	$0.02687	$0.06511	$0.03346	$0.12544	$0.02241	$0.06530	$0.03721	$0.12492
Primary		$0.13726	$0.01853	$0.06783	$0.03308	$0.11944	$0.01850	$0.06783	$0.03308	$0.11941	$0.01850	$0.06783	$0.03308	$0.11941	$0.01346	$0.06298	$0.03683	$0.11327
Transmission		$0.12880	$0.00179	$0.07246	$0.03362	$0.10787	$0.00179	$0.07246	$0.03362	$0.10787	$0.00179	$0.07246	$0.03362	$0.10787	$0.00228	$0.05831	$0.03737	$0.09796

SCHEDULE S	Total Rates Eff. 3/1/05	RDSA Methodology - Ph 2 Settlement RRQs				GRC Phase 2 Settlement Rates				GRC2 Methods - Ph 2 Settlement RRQs				GRC2 Supp. Testimony (2006 Sales)			
		Dist	Gen	Other	Total	Dist	Gen	Other	Total	Dist	Gen	Other	Total	Dist	Gen	Other	Total
METER CHARGE ($/MO.)																	
Small - Single & Polyphase	$6.80	$6.80			$6.80	$6.80			$6.80	$6.80			$6.80	$7.70			$7.70
Medium (50-499 kW)	$6.00	$6.00			$6.00	$6.00			$6.00	$6.00			$6.00	$7.90			$7.90
Supplemental Standby																	
Meter Charge	$186.00	$186.00			$186.00	$186.00			$186.00	$186.00			$186.00	$186.00			$186.00
CUST CHARGE ($/MO.)																	
Small L&P (≤ 50 kW)																	
Single Phase	$8.10	$8.10			$8.10	$8.10			$8.10	$8.10			$8.10	$17.00			$17.00
Poly Phase	$12.00	$12.00			$12.00	$12.00			$12.00	$12.00			$12.00	$26.00			$26.00
Medium L&P (50-499 kW)	$75.00	$75.00			$75.00	$100.00			$100.00	$100.00			$100.00	$100.00			$100.00
Medium L&P (500-999 kW)																	
Secondary	$175.00	$175.00			$175.00	$275			$275	$275			$275	$275			$275
Primary	$140.00	$140.00			$140.00	$400			$400	$400			$400	$400			$400
Transmission	$610.00	$610.00			$610.00	$1,200			$1,200	$1,200			$1,200	$1,200			$1,200
Large L&P (≥ 1000 kW)																	
Secondary	$385.00	$385.00			$385.00	$600			$600	$600			$600	$600			$600
Primary	$310.00	$310.00			$310.00	$800			$800	$800			$800	$800			$800
Transmission	$715.00	$715.00			$715.00	$1,500			$1,500	$1,500			$1,500	$1,500			$1,500
Reduced CUST CHARGE ($/MO.)																	
Small L&P (≤ 50 kW)	$6.60	$6.60			$6.60	$10.39			$10.39	$10.39			$10.39	$10.39			$10.39
Medium L&P (50-499 kW)	$56.60	$56.60			$56.60	$42.98			$42.98	$42.98			$42.98	$42.98			$42.98
Medium L&P (500-999 kW)	$56.60	$56.60			$56.60	$42.98			$42.98	$42.98			$42.98	$42.98			$42.98
RES CHARGE ($/kW/mo)																	
(applies to 85% of Res Cap)																	
Secondary	$2.52	$0.91	$0.82	$0.63	$2.36	$0.81	$0.25	$0.63	$1.69	$0.81	$0.25	$0.63	$1.69	$1.87	$0.19	$0.63	$2.69
Primary	$2.67	$0.96	$0.87	$0.63	$2.46	$0.75	$0.24	$0.63	$1.63	$0.75	$0.24	$0.63	$1.63	$1.87	$0.19	$0.63	$2.69
Transmission	$0.45	$0.00	-$0.22	$0.63	$0.41	$0.10	$0.12	$0.63	$0.85	$0.10	$0.12	$0.63	$0.85	$0.26	$0.14	$0.63	$1.03
ENERGY ($/kWh)																	
Secondary																	
Smr Peak	$0.46285	$0.09099	$0.26827	$0.03809	$0.39735	$0.06255	$0.10927	$0.03809	$0.20991	$0.06255	$0.10927	$0.03809	$0.20991	$0.14545	$0.08066	$0.04111	$0.26722
Smr Part-Peak	$0.15508	$0.02707	$0.07184	$0.03809	$0.13699	$0.02502	$0.09594	$0.03809	$0.15904	$0.02502	$0.09594	$0.03809	$0.15904	$0.05818	$0.07081	$0.04111	$0.17010
Smr Off-Peak	$0.07690	$0.00998	$0.02258	$0.03809	$0.07065	$0.01251	$0.06858	$0.03809	$0.11917	$0.01251	$0.06858	$0.03809	$0.11917	$0.02909	$0.05062	$0.04111	$0.12082
Wtr Part-Peak	$0.14175	$0.02391	$0.06364	$0.03809	$0.12563	$0.01903	$0.09227	$0.03809	$0.14939	$0.01903	$0.09227	$0.03809	$0.14939	$0.04425	$0.06811	$0.04111	$0.15347
Wtr Off-Peak	$0.08862	$0.01275	$0.02982	$0.03809	$0.08065	$0.01268	$0.07240	$0.03809	$0.12317	$0.01268	$0.07240	$0.03809	$0.12317	$0.02950	$0.05344	$0.04111	$0.12405
Primary																	
Smr Peak	$0.44645	$0.02194	$0.30652	$0.03891	$0.36737	$0.05855	$0.10259	$0.03891	$0.20005	$0.05855	$0.10259	$0.03891	$0.20005	$0.14545	$0.07889	$0.04193	$0.26628
Smr Part-Peak	$0.14471	$0.00646	$0.07845	$0.03891	$0.12382	$0.02342	$0.09163	$0.03891	$0.15395	$0.02342	$0.09163	$0.03891	$0.15395	$0.05818	$0.07046	$0.04193	$0.17057
Smr Off-Peak	$0.07220	$0.00234	$0.02395	$0.03891	$0.06519	$0.01171	$0.06612	$0.03891	$0.11673	$0.01171	$0.06612	$0.03891	$0.11673	$0.02909	$0.05084	$0.04193	$0.12186
Wtr Part-Peak	$0.13175	$0.00568	$0.06875	$0.03891	$0.11334	$0.01781	$0.08671	$0.03891	$0.14343	$0.01781	$0.08671	$0.03891	$0.14343	$0.04425	$0.06668	$0.04193	$0.15285
Wtr Off-Peak	$0.08268	$0.00299	$0.03180	$0.03891	$0.07369	$0.01187	$0.06972	$0.03891	$0.12050	$0.01187	$0.06972	$0.03891	$0.12050	$0.02950	$0.05361	$0.04193	$0.12504
Transmission																	
Smr Peak	$0.42867	$0.03780	$0.29782	$0.03717	$0.37279	$0.00000	$0.05222	$0.03717	$0.08939	$0.00000	$0.05222	$0.03717	$0.08939	$0.00000	$0.05811	$0.04019	$0.09829
Smr Part-Peak	$0.09998	$0.00746	$0.04606	$0.03717	$0.09069	$0.00000	$0.04672	$0.03717	$0.08388	$0.00000	$0.04672	$0.03717	$0.08388	$0.00000	$0.05198	$0.04019	$0.09216
Smr Off-Peak	$0.07468	$0.00501	$0.02676	$0.03717	$0.06894	$0.00000	$0.03394	$0.03717	$0.07110	$0.00000	$0.03394	$0.03717	$0.07110	$0.00000	$0.03776	$0.04019	$0.07795
Wtr Part-Peak	$0.11158	$0.00894	$0.05463	$0.03717	$0.10074	$0.00000	$0.04441	$0.03717	$0.08157	$0.00000	$0.04441	$0.03717	$0.08157	$0.00000	$0.04941	$0.04019	$0.08959
Wtr Off-Peak	$0.08432	$0.00628	$0.03387	$0.03717	$0.07731	$0.00000	$0.03582	$0.03717	$0.07299	$0.00000	$0.03582	$0.03717	$0.07299	$0.00000	$0.03986	$0.04019	$0.08004
Reactive Dem Chrg ($/kVAR)	$0.15	$0.15			$0.15	$0.15			$0.15	$0.15			$0.15	$0.15			$0.15
AVG RATES																	
Secondary	$0.22968	$0.05851	$0.08977	$0.06044	$0.20872	$0.05023	$0.08975	$0.06044	$0.20042	$0.05023	$0.08975	$0.06044	$0.20042	$0.11552	$0.06624	$0.06347	$0.24523
Primary	$0.20624	$0.04257	$0.08220	$0.06050	$0.18527	$0.05003	$0.08258	$0.06050	$0.19311	$0.05003	$0.08258	$0.06050	$0.19311	$0.11172	$0.06350	$0.06353	$0.23875
Transmission	$0.12847	$0.01407	$0.04312	$0.05974	$0.11694	$0.01267	$0.04312	$0.05974	$0.11553	$0.01267	$0.04312	$0.05974	$0.11553	$0.01836	$0.04798	$0.06277	$0.12911

		Total Rates Eff. 3/1/05	RDSA Methodology - Ph 2 Settlement RRQs				GRC Phase 2 Settlement Rates				GRC2 Methods - Ph 2 Settlement RRQs				GRC2 Supp. Testimony (2006 Sales)			
			Dist	Gen	Other	Total	Dist	Gen	Other	Total	Dist	Gen	Other	Total	Dist	Gen	Other	Total
E-19/E-20 CREDITS																		
CUST CHARGE ($/MO.)																		
Standard Non-Firm		$190.00	$190.00			$190.00	$190.00			$190.00	$190.00			$190.00	$190.00			$190.00
Non-Firm with UFR		$200.00	$200.00			$200.00	$200.00			$200.00	$200.00			$200.00	$200.00			$200.00
DEMAND ($/kW)																		
All Voltages	Smr Pk	-$7.50	-$7.50			-$7.50	-$7.50			-$7.50	-$7.50			-$7.50	-$7.50			-$7.50
	Smr Pt-Pk	-$0.50	-$0.50			-$0.50	-$0.50			-$0.50	-$0.50			-$0.50	-$0.50			-$0.50
	Smr Max																	
	Wtr Pt-Pk	-$0.50	-$0.50			-$0.50	-$0.50			-$0.50	-$0.50			-$0.50	-$0.50			-$0.50
	Wtr Max																	
ENERGY ($/kWh)																		
All Voltages	Smr Pk	-$0.01247	-$0.01247			-$0.01247	-$0.01247			-$0.01247	-$0.01247			-$0.01247	-$0.01247			-$0.01247
	Smr Pt-Pk	-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132
	Smr Off-Pk	-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132
	Wtr Pt-Pk	-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132
	Wtr Off-Pk	-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132	-$0.00132			-$0.00132
UFR Credit		-$0.00091	-$0.00091			-$0.00091	-$0.00091			-$0.00091	-$0.00091			-$0.00091	-$0.00091			-$0.00091
Non-Comp ($/kWh	Level 1	$8.40	$8.40			$8.40	$8.40			$8.40	$8.40			$8.40	$8.40			$8.40
Non-Comp ($/kWh	Level 2	$4.20	$4.20			$4.20	$4.20			$4.20	$4.20			$4.20	$4.20			$4.20

(END OF APPENDIX E)

APPENDIX F

SUPPLEMENTAL AGRICULTURAL SETTLEMENT

SUPPLEMENTAL AGRICULTURAL SETTLEMENT

IN APPLICATION 04-06-024

I. SUPPLEMENTAL AGRICULTURAL SETTLEMENT AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this settlement (Settling Parties) agree on a mutually acceptable outcome to issues regarding rates for Agricultural customers in Application (A.) 04-06-024, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This Agricultural Settlement is supplemental to the Settlement In Application 04-06-024 filed in this proceeding on May 13, 2005 (May 13 Settlement), in that it uses the revenue allocation agreed to in the May 13 Settlement and addresses Agricultural issues that were not resolved in the May 13 Settlement. The Settling Parties intend that the complementary outcomes of this Agricultural Settlement and the May 13 Settlement be consolidated in the Commission's final decision in this proceeding.

II. AGRICULTURAL SETTLEMENT PARTIES

The Settling Parties are as follows:

Agricultural Energy Consumers Association (AECA)

California Farm Bureau Federation (CFBF)

Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC)

Pacific Gas and Electric Company (PG&E)

II. AGRICULTURAL SETTLEMENT CONDITIONS

The Settling Parties agree that this Agricultural Settlement resolves the specified

issues raised in A.04-06-024 by the Settling Parties, subject to the following reservations:

1. This Agricultural 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 Agricultural Settlement builds on the underlying marginal cost and revenue allocation in the May 13 Settlement and incorporates that agreement by reference. All four Settling Parties (AECA, CFBF, CAC/EPUC, and PG&E) are signatories to the May 13 Settlement.

2. This Agricultural 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 Agricultural 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 Agricultural Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest, in accordance with Rule 51.1(e).

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

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

6. The Settling Parties shall jointly request and actively support timely Commission approval of this Agricultural Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 Agricultural Settlement to be interpreted and treated as a unified, integrated agreement incorporating the May 13 Settlement which forms the foundation for the Agricultural rate design agreed to herein. In the event the Commission rejects or modifies this Agricultural Settlement or the underlying May 13 Settlement, the Settling Parties reserve their rights under Rule 51.7.

III. AGRICULTURAL SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

> On August 27, 2004, the *Scoping Memo And Ruling of Assigned Commissioner* (ACR) stated: "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding). ...

The three general subjects of the application are marginal costs, revenue allocation and rate design." The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 13, 2005, sixteen parties to this proceeding filed the May 13 Settlement regarding marginal cost and revenue allocation issues as well as Streetlight and Submetering rate design issues, and they stated that discussions would continue in an effort to reach agreement on the remaining rate design issues. The May 13 Settlement was filed before all rate design issues were resolved due to a June 1, 2005 deadline relating to a key feature of the May 13 Settlement.

On June 3, 2005, three parties to this proceeding filed the Supplemental Residential Settlement In Application 04-06-024, and four parties to this proceeding filed the Supplemental Small Light and Power Settlement In Application 04-06-024.

After several discussions, on June 30, 2005, four parties to the Agricultural rate design settlement discussions reached an agreement in principle, building from the Agricultural revenue allocation agreed to in the May 13 Settlement.

IV. AGRICULTURAL SETTLEMENT TERMS

1. Generally

The Settling Parties agree that the primary purpose of rate design for the

Agricultural class is to take the revenue allocation reached for that class in the May 13 Settlement and ensure that it is fully recovered through Agricultural rates in a manner that is just and reasonable, in the public interest, provides agricultural customers with pricing options that meet their operational needs, and reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the rates set forth herein in Attachment A are consistent with the revenue allocation set forth in Table 2 of the May 13 Settlement Agreement, and that the actual rates calculated in accordance with this Agricultural Settlement may be somewhat different than those set forth below. The tables provided in Attachment A include comparisons of PG&E's litigation positions with the outcome for the Agricultural Settlement. (This comparison meets Rule 51.1(c) requirements, because ORA did not take a position on rates for the agricultural rate schedules.)

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

The Settling Parties further agree that this Agricultural Settlement will be followed by the Settling Parties' efforts to reach agreement on additional agricultural class definition issues in A.04-06-024. 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 Agricultural Settlement or the May 13 Settlement.

In terms of the 36 specific issues identified in Attachment A to the ACR and in

subsequent ALJ rulings, this Agricultural Settlement resolves portions of Rate Design issue 3.6 (for the Agricultural customer class only) and 3.15. This Agricultural Settlement does not address Rate Design issue 3.14 (the definition of the Agricultural class).

2. A.04-06-024 Agricultural Rate Changes on January 1, 2006

The Settling Parties agree that rates to collect the revenue allocated to the Agricultural customer class under the May 13 Settlement on an overall revenue-neutral basis shall be designed as set forth below, and that these rates shall serve as the starting point for determining the changes to rates necessary to collect the adopted revenue requirement on January 1, 2006. All items below are effective Janaury 1, 2006 unless otherwise indicated.

1. Pursuant to the June 2, 2005 motion filed by CFBF, the agricultural applicability statement shall be addressed as a separate policy issue through continuing settlement negotiations in a separate 2003 GRC Phase 2 extension proceeding. If agreement is not reached, hearings shall occur in September 2005, with a final decision sought by January 2006 establishing the agricultural applicability definition to use in PG&E's 2007 GRC Phase 2 proceeding. Parties agree the determination of PG&E's agricultural applicability statement does not affect the development or implementation of PG&E's January 1, 2006 electric rates.

2. PG&E's proposed rate consolidation shall be dropped, and all current agricultural rate schedules shall be retained to the extent provided herein. Schedule AG-7 shall be eliminated May **1**, 2006, with customers given individual rate analyses to make a rate schedule selection.

3. Ratcheted demand charges shall be discontinued. The demand charge rate limiter and the drought relief option shall be eliminated, as both are tied to ratcheted demand charge impacts that are being eliminated. Balance of contract provisions and a minimum demand tied to 75 percent of the nameplate rating of the two largest motor provisions shall also be eliminated.

4. Schedules AG-4C and AG-5C shall be redesigned to replace the current off-peak ratcheted maximum demand charges with a standard maximum demand charge as of January 1, 2006. Voltage discounts for Schedules AG-4C and AG-5C shall be made available by May 1, 2006.

5. The TOU meter Installation and Processing charges shall be eliminated May 1, 2006. The two current daily TOU meter charges shall be retained, with the lower daily charge applicable only to customers who paid the Installation charge prior to its elimination.

6. The current Diesel Alternative Power (DAP) option and the Natural Gas Alternative Power (GAP) option shall be discontinued as of May 1, 2006.

7. The Settling Parties agree that it is reasonable to defer further consideration of account aggregation proposals to Phase 2 of PG&E's 2007 GRC. PG&E will provide the staff and other resources necessary to design and perform a study examining the implications of agricultural and water agency pumping load account aggregation in anticipation of its Phase 2 filing. This analysis is intended as a follow-up study to PG&E's earlier Assembly Bill 1421 Report. The study framework, methodology, and implementation will be developed through mutual agreement between PG&E, AECA, CFBF, and EBMUD.

8. PG&E will make available to AECA and CFBF class-specific data at the distribution planning area level, including coincident peak demand, billed monthly demand, connected load, and seasonal billed consumption at the time it files its Phase 2 submission.

9. Schedule level revenue allocation and rate design shall use equal percentage change methods established in Rate Design Settlement Agreement (RDSA) Decision 04-02-062, except for the rate design or other modifications specified herein. Oil pumping Schedule E-37 rates shall be set equal to the rates on Schedule AG-5B.

10. Illustrative rates for settlement agricultural schedules are presented in Attachment A, and include PG&E's last litigation position to fulfill the comparison exhibit requirements of Rule 51.1(c). The settlement rates were developed to collect the revenue allocated to the Agricultural class set forth in Table 2 (column 4) of the May 13 Settlement. Adopted revenue requirements shall be applied to these initial rates to determine rates effective in 2006. These rates are the best estimate of the rates that would be calculated based on actual Commission decisions at that time. However, the actual rates may be somewhat different than those shown in Attachment A.

V. AGRICULTURAL 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 Agricultural Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the Agricultural Settlement as indicated below. In

witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Agricultural Settlement on behalf of the Settling Parties they represent.

This Agricultural Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Agricultural Energy Consumers Association

By: _____

Title: Asst. Executive Director

California Farm Bureau Federation

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Agricultural Settlement on behalf of the Settling Parties they represent.

This Agricultural Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Agricultural Energy Consumers Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: Associate Counsel

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: _____

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This Agricultural Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Agricultural Energy Consumers Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: [illegible]

Title: Counsel

Pacific Gas and Electric Company

By: _____

Title: _____

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This Agricultural Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Agricultural Energy Consumers Association

By: _____

Title: _____

California Farm Bureau Federation

By: _____

Title: _____

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

Pacific Gas and Electric Company

By: Andrew L. Niven

Title: Attorney

ATTACHMENT A

To Supplemental Agricultural
Settlement in Application 04-06-024

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

		Current	Settlement Rates					Comparison Exhibit			
		Total Rates	RDSA Method/No Ratchets - Ph 2 Settlement RRQs					PG&E Litigation Position - Exhibit (PG&E-11) *			
		Eff. 3/1/05	Dist	Gen	Other	Total		Dist	Gen	Other	Total
AG 1A											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$12.00	$12.00			$12.00	**AG-NA:**	$15.00			$15.00
DEMAND	Smr	$2.57	$2.73	$0.00		$2.73		$2.42	$0.52		$2.94
(per hp of con. load)	Wtr	$2.36	$2.51	$0.00		$2.51		$1.62	$0.00		$1.62
ENERGY ($/kW)	Smr	$0.15854	$0.06040	$0.05424	$0.03253	$0.14717		$0.05018	$0.05511	$0.03642	$0.14171
	Wtr	$0.15854	$0.06040	$0.05424	$0.03253	$0.14717		$0.03345	$0.04653	$0.03642	$0.11640
AVG RATES		$0.25857	$0.16680	$0.05424	$0.03253	$0.25356		$0.14110	$0.06048	$0.03642	$0.23800
						-1.94%					-8.60%
AG RA											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$12.00	$12.00			$12.00	**AG-TA:**	$20.00			$20.00
METER CHARGE ($/MO.)		$6.80	$6.80			$6.80		$7.70			$7.70
DEMAND	Smr	$2.58	$2.75	$0.00		$2.75		$2.62	$0.65		$3.27
(per hp of con. load)	Wtr	$2.36	$2.52	$0.00		$2.52		$1.75	$0.00		$1.75
ENERGY ($/kW)	Smr Peak	$0.34527	$0.08631	$0.18536	$0.03018	$0.30184		$0.07505	$0.13678	$0.03371	$0.24554
	Smr Off-Peak	$0.09619	$0.02015	$0.03671	$0.03018	$0.08704		$0.02502	$0.04280	$0.03371	$0.10153
	Wtr Part-Peak	$0.09190	$0.01899	$0.03416	$0.03018	$0.08332		$0.07732	$0.05351	$0.03371	$0.16454
	Wtr Off-Peak	$0.07727	$0.01510	$0.02544	$0.03018	$0.07071		$0.05155	$0.04199	$0.03371	$0.12725
AVG RATES		$0.17764	$0.10057	$0.04141	$0.03018	$0.17216		$0.10293	$0.05748	$0.03371	$0.19412
						-3.09%					14.50%
AG VA											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$12.00	$12.00			$12.00	**AG-TA:**	$20.00			$20.00
METER CHARGE ($/MO.)		$6.80	$6.80			$6.80		$7.70			$7.70
DEMAND	Smr	$2.58	$2.75	$0.00		$2.75		$2.62	$0.65		$3.27
(per hp of con. load)	Wtr	$2.36	$2.52	$0.00		$2.52		$1.75	$0.00		$1.75
ENERGY ($/kW)	Smr Peak	$0.33925	$0.08118	$0.18434	$0.03025	$0.29576		$0.07505	$0.13678	$0.03371	$0.24554
	Smr Off-Peak	$0.09266	$0.01852	$0.03506	$0.03025	$0.08382		$0.02502	$0.04280	$0.03371	$0.10153
	Wtr Part-Peak	$0.09009	$0.01785	$0.03352	$0.03025	$0.08161		$0.07732	$0.05351	$0.03371	$0.16454
	Wtr Off-Peak	$0.07570	$0.01420	$0.02480	$0.03025	$0.06925		$0.05155	$0.04199	$0.03371	$0.12725
AVG RATES		$0.17918	$0.09917	$0.04364	$0.03025	$0.17306		$0.10293	$0.05748	$0.03371	$0.19412
						-3.41%					14.50%

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

		Current	Settlement Rates					Comparison Exhibit			
		Total Rates	RDSA Method/No Ratchets - Ph 2 Settlement RRQs					PG&E Litigation Position - Exhibit (PG&E-11) *			
		Eff. 3/1/05	Dist	Gen	Other	Total		Dist	Gen	Other	Total
AG 4A											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$12.00	$12.00			$12.00	**AG-TA:**	$20.00			$20.00
METER CHARGE ($/MO.)		$6.80	$6.80			$6.80		$7.70			$7.70
DEMAND	Smr	$2.58	$2.73	$0.02		$2.75		$2.62	$0.65		$3.27
(per hp of con. load)	Wtr	$2.37	$2.50	$0.03		$2.53		$1.75	$0.00		$1.75
ENERGY ($/kW)	Smr Peak	$0.34030	$0.08178	$0.18483	$0.03009	$0.29670		$0.07505	$0.13678	$0.03371	$0.24554
	Smr Off-Peak	$0.08475	$0.01644	$0.03046	$0.03009	$0.07698		$0.02502	$0.04280	$0.03371	$0.10153
	Wtr Part-Peak	$0.09078	$0.01800	$0.03408	$0.03009	$0.08216		$0.07732	$0.05351	$0.03371	$0.16454
	Wtr Off-Peak	$0.07637	$0.01432	$0.02537	$0.03009	$0.06978		$0.05155	$0.04199	$0.03371	$0.12725
AVG RATES		$0.17692	$0.09825	$0.04269	$0.03009	$0.17102 -3.33%		$0.10293	$0.05748	$0.03371	$0.19412 14.50%
AG 5A											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$12.00	$12.00			$12.00	**AG-TA:**	$20.00			$20.00
METER CHARGE ($/MO.)		$6.80	$6.80			$6.80		$7.70			$7.70
DEMAND	Smr	$5.83	$5.75	$0.33		$6.08		$2.62	$0.65		$3.27
(per hp of con. load)	Wtr	$5.83	$5.75	$0.33		$6.08		$1.75	$0.00		$1.75
ENERGY ($/kW)	Smr Peak	$0.25152	$0.03955	$0.14636	$0.02909	$0.21500		$0.07505	$0.13678	$0.03371	$0.24554
	Smr Off-Peak	$0.06585	$0.00812	$0.02239	$0.02909	$0.05959		$0.02502	$0.04280	$0.03371	$0.10153
	Wtr Part-Peak	$0.07161	$0.00908	$0.02624	$0.02909	$0.06441		$0.07732	$0.05351	$0.03371	$0.16454
	Wtr Off-Peak	$0.06059	$0.00723	$0.01888	$0.02909	$0.05519		$0.05155	$0.04199	$0.03371	$0.12725
AVG RATES		$0.14666	$0.07128	$0.03989	$0.02909	$0.14025 -4.37%		$0.10293	$0.05748	$0.03371	$0.19412 14.50%
AG 1B											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	**AG-NB:**	$35.00			$35.00
DEMAND ($/kW)	Smr Max	$3.08	$5.31	$0.05		$5.36		$6.26	$2.09		$8.35
	Wtr Max	$1.86	$3.70	$0.02		$3.71		$2.52	$0.00		$2.52
Pri Volt Disc	Smr Max	$0.42	$0.73	$0.00		$0.73		$0.11	$0.62		$0.73
	Wtr Max	$0.31	$0.63	$0.00		$0.63		$0.07	$0.00		$0.07
Tran Volt Disc	Smr Max							$2.55	$1.26		$3.81
	Wtr Max							$1.91	$0.00		$1.91
ENERGY ($/kWh)	Smr	$0.13775	$0.04533	$0.05028	$0.03062	$0.12622		$0.00000	$0.05178	$0.03451	$0.08629
	Wtr	$0.13775	$0.04533	$0.05028	$0.03062	$0.12622		$0.00000	$0.04274	$0.03451	$0.07725
AVG RATES		$0.17922	$0.08914	$0.05052	$0.03062	$0.17028 -4.99%		$0.05015	$0.05823	$0.03451	$0.14289 -20.60%

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

AG RB
PROPOSED RATES

		Current	Settlement Rates					Comparison Exhibit			
		Total Rates	RDSA Method/No Ratchets - Ph 2 Settlement RRQs					PG&E Litigation Position - Exhibit (PG&E-11) *			
		Eff. 3/1/05	Dist	Gen	Other	Total		Dist	Gen	Other	Total
CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	AG-TB:	$40.00			$40.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$2.93	$3.04	$0.05		$3.09		$2.03	$2.72		$4.75
	Smr Max	$3.10	$4.63	$0.05		$4.68		$4.46	$2.49		$6.95
	Wtr Max	$1.87	$4.40	$0.06		$4.46		$2.67	$0.00		$2.67
Pri Volt Disc	Smr Peak					$0.00		$0.00	$0.67		$0.67
	Smr Max	$0.42	$0.65	$0.00		$0.65		$0.10	$0.00		$0.10
	Wtr Max	$0.31	$0.72	$0.02		$0.74		$0.09	$0.00		$0.09
Tran Volt Disc	Smr Peak							$0.00	$1.24		$1.24
	Smr Max							$2.44	$0.00		$2.44
	Wtr Max							$1.94	$0.00		$1.94
ENERGY ($/kWh)	Smr Peak	$0.29056	$0.02700	$0.18596	$0.03011	$0.24306		$0.00000	$0.05788	$0.03203	$0.08991
	Smr Off-Peak	$0.09763	$0.00791	$0.04698	$0.03011	$0.08500		$0.00000	$0.03999	$0.03203	$0.07202
	Wtr Part-Peak	$0.09543	$0.00769	$0.04540	$0.03011	$0.08319		$0.00000	$0.04820	$0.03203	$0.08023
	Wtr Off-Peak	$0.07948	$0.00613	$0.03389	$0.03011	$0.07013		$0.00000	$0.03804	$0.03203	$0.07007
AVG RATES		$0.15781	$0.06801	$0.04990	$0.03011	$0.14802		$0.02310	$0.05347	$0.03203	$0.10860
						-6.20%					3.30%

AG VB
PROPOSED RATES

CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	AG-TB:	$40.00			$40.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$2.92	$2.96	$0.10		$3.06		$2.03	$2.72		$4.75
	Smr Max	$3.08	$4.54	$0.13		$4.67		$4.46	$2.49		$6.95
	Wtr Max	$1.87	$3.73	$0.11		$3.83		$2.67	$0.00		$2.67
Pri Volt Disc	Smr Peak					$0.00		$0.00	$0.67		$0.67
	Smr Max	$0.42	$0.61	$0.03		$0.63		$0.10	$0.00		$0.10
	Wtr Max	$0.32	$0.66	$0.00		$0.66		$0.09	$0.00		$0.09
Tran Volt Disc	Smr Peak							$0.00	$1.24		$1.24
	Smr Max							$2.44	$0.00		$2.44
	Wtr Max							$1.94	$0.00		$1.94
ENERGY ($/kWh)	Smr Peak	$0.26136	$0.03374	$0.15792	$0.02985	$0.22150		$0.00000	$0.05788	$0.03203	$0.08991
	Smr Off-Peak	$0.09390	$0.01046	$0.04231	$0.02985	$0.08262		$0.00000	$0.03999	$0.03203	$0.07202
	Wtr Part-Peak	$0.09416	$0.01049	$0.04250	$0.02985	$0.08283		$0.00000	$0.04820	$0.03203	$0.08023
	Wtr Off-Peak	$0.07865	$0.00836	$0.03177	$0.02985	$0.06998		$0.00000	$0.03804	$0.03203	$0.07007
AVG RATES		$0.15302	$0.06704	$0.04704	$0.02985	$0.14392		$0.02310	$0.05347	$0.03203	$0.10860
						-5.94%					3.30%

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

		Current	Settlement Rates					Comparison Exhibit			
		Total Rates	RDSA Method/No Ratchets - Ph 2 Settlement RRQs					PG&E Litigation Position - Exhibit (PG&E-11) *			
		Eff. 3/1/05	Dist	Gen	Other	Total		Dist	Gen	Other	Total
AG 4B											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	**AG-TB:**	$40.00			$40.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$2.91	$2.94	$0.10		$3.04		$2.03	$2.72		$4.75
	Smr Max	$3.07	$4.64	$0.16		$4.80		$4.46	$2.49		$6.95
	Wtr Max	$1.86	$3.78	$0.13		$3.91		$2.67	$0.00		$2.67
Pri Volt Disc	Smr Peak					$0.00		$0.00	$0.67		$0.67
	Smr Max	$0.42	$0.76	$0.03		$0.80		$0.10	$0.00		$0.10
	Wtr Max	$0.31	$1.02	$0.03		$1.05		$0.09	$0.00		$0.09
Tran Volt Disc	Smr Peak							$0.00	$1.24		$1.24
	Smr Max							$2.44	$0.00		$2.44
	Wtr Max							$1.94	$0.00		$1.94
ENERGY ($/kWh)	Smr Peak	$0.21891	$0.01818	$0.13608	$0.02956	$0.18382		$0.00000	$0.05788	$0.03203	$0.08991
	Smr Off-Peak	$0.08118	$0.00570	$0.03600	$0.02956	$0.07125		$0.00000	$0.03999	$0.03203	$0.07202
	Wtr Part-Peak	$0.08779	$0.00632	$0.04080	$0.02956	$0.07667		$0.00000	$0.04820	$0.03203	$0.08023
	Wtr Off-Peak	$0.07354	$0.00501	$0.03046	$0.02956	$0.06502		$0.00000	$0.03804	$0.03203	$0.07007
AVG RATES		$0.14488	$0.05800	$0.04764	$0.02956	$0.13520		$0.02310	$0.05347	$0.03203	$0.10860
						-6.68%					3.30%
AG 4C											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$16.00	$54.00			$54.00	**AG-TC:**	$54.00			$54.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$6.68	$4.36	$2.84		$7.20		$5.65	$6.05		$11.70
	Smr Part-Peak	$4.81	$1.02	$0.53		$1.55		$1.42	$1.21		$2.63
	Smr Off-Peak / Max	$1.60	$1.82	$0.00		$1.82		$3.55	$0.00		$3.55
	Wtr Part-Peak	$0.42	$0.51	$0.00		$0.51		$0.81	$0.00		$0.81
	Wtr Off-Peak / Max	$0.22	$0.72	$0.00		$0.72		$1.69	$0.00		$1.69
Pri Volt Disc	Smr Peak		$0.07	$0.77		$0.84		$0.07	$1.13		$1.20
	Wtr Max		$0.04	$0.00		$0.04		$0.04	$0.00		$0.04
Tran Volt Disc	Smr Peak		$0.85	$1.43		$2.28		$1.53	$2.07		$3.60
	Wtr Max		$0.52	$0.00		$0.52		$0.99	$0.00		$0.99
ENERGY ($/kWh)	Smr Peak	$0.10759	$0.00000	$0.04279	$0.02920	$0.07198		$0.00000	$0.06235	$0.03194	$0.09429
	Smr Part-Peak	$0.08021	$0.00000	$0.03756	$0.02920	$0.06676		$0.00000	$0.05474	$0.03194	$0.08668
	Smr Off-Peak	$0.07130	$0.00000	$0.02685	$0.02920	$0.05605		$0.00000	$0.03913	$0.03194	$0.07107
	Wtr Part-Peak	$0.10750	$0.00000	$0.03613	$0.02920	$0.06533		$0.00000	$0.05265	$0.03194	$0.08459
	Wtr Off-Peak	$0.09262	$0.00000	$0.02835	$0.02920	$0.05754		$0.00000	$0.04131	$0.03194	$0.07325
AVG RATES		$0.14136	$0.06731	$0.03834	$0.02920	$0.13485		$0.03977	$0.05710	$0.03194	$0.12881
						-4.60%					26.50%

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

		Current	Settlement Rates					Comparison Exhibit			
		Total Rates	RDSA Method/No Ratchets - Ph 2 Settlement RRQs					PG&E Litigation Position - Exhibit (PG&E-11) *			
		Eff. 3/1/05	Dist	Gen	Other	Total		Dist	Gen	Other	Total
AG 5B											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	**AG-TB:**	$40.00			$40.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$2.87	$3.02	$0.00		$3.02		$2.03	$2.72		$4.75
	Smr Max	$6.94	$9.16	$0.00		$9.16		$4.46	$2.49		$6.95
	Wtr Max	$4.67	$7.56	$0.00		$7.56		$2.67	$0.00		$2.67
Pri Volt Disc	Smr Peak					$0.00		$0.00	$0.67		$0.67
	Smr Max	$1.00	$1.32	$0.00		$1.32		$0.10	$0.00		$0.10
	Wtr Max	$0.69	$1.12	$0.00		$1.12		$0.09	$0.00		$0.09
Trans Volt Disc	Smr Peak					$0.00		$0.00	$1.24		$1.24
	Smr Max	$5.14	$6.78	$0.00		$6.78		$2.44	$0.00		$2.44
	Wtr Max	$3.45	$5.58	$0.00		$5.58		$1.94	$0.00		$1.94
ENERGY ($/kWh)	Smr Peak	$0.15339	$0.00318	$0.09657	$0.02793	$0.12768		$0.00000	$0.05788	$0.03203	$0.08991
	Smr Off-Peak	$0.05511	$0.00088	$0.02019	$0.02793	$0.04900		$0.00000	$0.03999	$0.03203	$0.07202
	Wtr Part-Peak	$0.06063	$0.00101	$0.02449	$0.02793	$0.05343		$0.00000	$0.04820	$0.03203	$0.08023
	Wtr Off-Peak	$0.05144	$0.00079	$0.01736	$0.02793	$0.04607		$0.00000	$0.03804	$0.03203	$0.07007
AVG RATES		$0.09858	$0.03554	$0.02911	$0.02793	$0.09258		$0.02310	$0.05347	$0.03203	$0.10860
						-6.09%					3.30%
AG 5C											
PROPOSED RATES											
CUST CHARGE ($/MO.)		$54.00	$54.00			$54.00	**AG-TC:**	$54.00			$54.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$9.77	$4.73	$3.04		$7.76		$5.65	$6.05		$11.70
	Smr Part-Peak	$5.95	$1.22	$0.62		$1.84		$1.42	$1.21		$2.63
	Smr Off-Peak / Max	$1.64	$3.71	$0.00		$3.71		$3.55	$0.00		$3.55
	Wtr Part-Peak	$0.75	$0.72	$0.00		$0.72		$0.81	$0.00		$0.81
	Wtr Off-Peak / Max	$0.11	$1.86	$0.00		$1.86		$1.69	$0.00		$1.69
Pri Volt Disc	Smr Peak		$0.07	$1.35		$1.42		$0.07	$1.13		$1.20
	Wtr Max		$0.04	$0.00		$0.04		$0.04	$0.00		$0.04
Trans Volt Disc	Smr Peak		$1.95	$2.48		$4.42		$1.53	$2.07		$3.60
	Wtr Max		$1.33	$0.00		$1.33		$0.99	$0.00		$0.99
ENERGY ($/kWh)	Smr Peak	$0.09125	$0.02027	$0.02861	$0.02786	$0.07674		$0.00000	$0.06235	$0.03194	$0.09429
	Smr Part-Peak	$0.06358	$0.00811	$0.02512	$0.02786	$0.06108		$0.00000	$0.05474	$0.03194	$0.08668
	Smr Off-Peak	$0.05278	$0.00405	$0.01796	$0.02786	$0.04986		$0.00000	$0.03913	$0.03194	$0.07107
	Wtr Part-Peak	$0.07391	$0.00614	$0.02416	$0.02786	$0.05816		$0.00000	$0.05265	$0.03194	$0.08459
	Wtr Off-Peak	$0.06131	$0.00409	$0.01896	$0.02786	$0.05091		$0.00000	$0.04131	$0.03194	$0.07325
AVG RATES		$0.09436	$0.03482	$0.02630	$0.02786	$0.08897		$0.03977	$0.05710	$0.03194	$0.12881
						-5.71%					26.50%

Pacific Gas and Electric Company
2003 GRC Phase 2
Agricultural Settlement Rates
Illustrative January 1, 2006 Rates

ATTACHMENT A

E-37
PROPOSED RATES

		Current Total Rates Eff. 3/1/05	Settlement Rates RDSA Method/No Ratchets - Ph 2 Settlement RRQs Dist	Gen	Other	Total		Comparison Exhibit PG&E Litigation Position - Exhibit (PG&E-11) * Dist	Gen	Other	Total
CUST CHARGE ($/MO.)		$16.00	$16.00			$16.00	E-37:	$40.00			$40.00
METER CHARGE ($/MO.)		$6.00	$6.00			$6.00		$7.90			$7.90
DEMAND ($/kW)	Smr Peak	$2.86	$3.02	$0.00		$3.02		$2.03	$2.72		$4.75
	Smr Max	$6.95	$9.16	$0.00		$9.16		$4.46	$2.49		$6.95
	Wtr Max	$4.67	$7.56	$0.00		$7.56		$2.67	$0.00		$2.67
Pri Volt Disc	Smr Peak					$0.00			$0.67		$0.67
	Smr Max	$1.02	$1.32	$0.00		$1.32		$0.10	$0.00		$0.10
	Wtr Max	$0.77	$1.12	$0.00		$1.12		$0.09	$0.00		$0.09
Trans Volt Disc	Smr Peak					$0.00			$1.24		$1.24
	Smr Max	$5.52	$6.78	$0.00		$6.78		$2.44	$0.00		$2.44
	Wtr Max	$3.70	$5.58	$0.00		$5.58		$1.94	$0.00		$1.94
ENERGY ($/kWh)	Smr Peak	$0.15279	$0.00318	$0.09657	$0.02793	$0.12768		$0.00000	$0.05788	$0.03066	$0.08854
	Smr Off-Peak	$0.05472	$0.00088	$0.02019	$0.02793	$0.04900		$0.00000	$0.03999	$0.03066	$0.07065
	Wtr Part-Peak	$0.06023	$0.00101	$0.02449	$0.02793	$0.05343		$0.00000	$0.04820	$0.03066	$0.07886
	Wtr Off-Peak	$0.05105	$0.00079	$0.01736	$0.02793	$0.04607		$0.00000	$0.03804	$0.03066	$0.06870
AVG RATES (w/ AG 5B Billing Determinants)		$0.09864	$0.03554	$0.02911	$0.02793	$0.09258 -6.15%		$0.02310	$0.05347	$0.03066	$0.10723 8.71%

* Exhibit (PG&E-11) presented rates, average rates, and percentage impacts by rate schedule only on the proposed consolidated basis:

Current Schedule	Proposed Consolidated Schedule
AG-1A	AG-NA
AG-RA	AG-TA
AG-VA	AG-TA
AG-4A	AG-TA
AG-5A	AG-TA
AG-1B	AG-NB
AG-RB	AG-TB
AG-VB	AG-TB
AG-4C	AG-TC
AG-5B	AG-TB
AG-5C	AG-TC
E-37	AG-TB

(END OF APPENDIX F)

APPENDIX G

SUPPLEMENTAL ENERGY RECOVERY BOND SETTLEMENT

SUPPLEMENTAL ENERGY RECOVERY BOND SETTLEMENT IN APPLICATION 04-06-024

I. SUPPLEMENTAL ENERGY RECOVERY BOND SETTLEMENT AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this settlement (Settling Parties) agree on a mutually acceptable outcome to the issue regarding energy recovery bonds in Application (A.) 04-06-024, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. Specifically, the Settling Parties agree on the resolution of Rate Design issue 3.16, which was added to the list of issues in this proceeding by the Administrative Law Judge's Ruling Amending Lists Of Issues, dated November 23, 2004 (ALJ Ruling). This ERB Settlement is supplemental to the Settlement In Application 04-06-024 filed in this proceeding on May 13, 2005 (May 13 Settlement), in that it uses the revenue allocation agreed to in the May 13 Settlement. The Settling Parties intend that the outcomes of this ERB Settlement and the May 13 Settlement be consolidated in the Commission's final decision in this proceeding.

II. ERB SETTLEMENT PARTIES

The Settling Parties are Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC) and Pacific Gas and Electric Company (PG&E).

II. ERB SETTLEMENT CONDITIONS

The Settling Parties agree that this ERB Settlement resolves Rate Design issue 3.16, subject to the following reservations:

1. This ERB Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matter described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to that matter. This ERB Settlement builds on the underlying marginal cost and revenue allocation in the May 13 Settlement and incorporates that agreement by reference. Both Settling Parties (CAC/EPUC and PG&E) are signatories to the May 13 Settlement.

2. This ERB 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 ERB 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 ERB Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest, in accordance with Rule 51.1(e).

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

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

6. The Settling Parties shall jointly request and actively support timely Commission approval of this ERB Settlement. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, 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 ERB Settlement to be interpreted and treated as a unified, integrated agreement incorporating the May 13 Settlement. In the event the Commission rejects or modifies this ERB Settlement or the underlying May 13 Settlement, the Settling Parties reserve their rights under Rule 51.7.

III. ERB SETTLEMENT HISTORY

On June 17, 2004, PG&E filed this Application and supporting testimony. This proceeding, A.04-06-024, is commonly referred to as Phase 2 of PG&E's 2003 test year General Rate Case.

> On August 27, 2004, the *Scoping Memo And Ruling of Assigned Commissioner* (ACR) stated: "The general purpose of this proceeding is to establish just and reasonable rates on an overall (total utility) revenue neutral basis using the revenue requirement determined in D.04-05-055, as may subsequently be modified in other proceedings (e.g., attrition adjustment proceeding, energy resource recovery account proceeding). ...

The three general subjects of the application are marginal costs, revenue allocation and rate design." The ACR went on to list the issues within each of these three subject areas and to establish a procedural schedule, among other things.

On December 6, 2004, PG&E served supplemental testimony.

On January 14, 2005, ORA served its initial testimony.

On February 18, 2004, PG&E served its rate update testimony.

On March 7, 2005, intervenors served their initial testimony.

On April 26, 2005, parties served their rebuttal testimony.

On May 3, 2005, PG&E served supplemental testimony.

In addition, PG&E served errata and corrections to its testimony on December 31, 2004, January 10, 2005, and April 8, 2005.

After providing notice to all parties pursuant to Rule 51.1(b) on February 17, 2005, PG&E hosted an initial settlement conference on March 9, 2005. Additional settlement discussions among most of the active major parties were held in subsequent weeks by conference calls. On May 13, 2005, sixteen parties to this proceeding filed the May 13 Settlement regarding marginal cost and revenue allocation issues as well as Streetlight and Submetering rate design issues, and they stated that discussions would continue in an effort to reach agreement on the remaining rate design issues. The May 13 Settlement was filed before all rate design issues were resolved due to a June 1, 2005 deadline relating to a key feature of the May 13 Settlement.

On June 3, 2005, three parties to this proceeding filed the Supplemental Residential Settlement In Application 04-06-024, and four parties to this proceeding filed the Supplemental Small Light and Power Settlement In Application 04-06-024.

After several discussions, on June 21, 2005, the two parties to the ERB settlement discussions reached an agreement in principle.

IV. ERB SETTLEMENT TERMS

Rate Design issue 3.16 states as follows (ALJ Ruling, pages 3-4):

> 3.16. The extent to which energy recovery bond charges payable by departing load customers are to be paid within the cost responsibility surcharge cap of $0.027 per kilowatt-hour (kWh).

PG&E filed responsive testimony on this ERB issue in Exhibit (PG&E-5), Section C, p. 1-6. In short, PG&E's testimony states that while the cap for departing load should

include the ERB, in the unlikely event the ERB can not be collected under the cap, the rates would be adjusted to ensure that the ERB is fully collected from the responsible customers.

In the referenced testimony, PG&E sets forth its proposal with regard to the extent to which energy recovery bond charges payable by Departing Load (DL) customers are to be paid within the cost responsibility surcharge (CRS) cap of $0.0270 per kWh, as follows:

> Decision 04-11-015, Ordering Paragraph 65, states the following:
>
> 65. The issue of whether Bond Charges should be included under the CRS cap of $0.027/kWh shall be addressed in Phase II of PG&E's General Rate Case (GRC) proceeding in A.04-06-024 or such other proceeding as may be subsequently determined by the Commission. In the interim, the cap shall apply to Bond Charges that accrue to non-exempted DL. The procedure and priority for recovering Bond Charges under the CRS cap from non-exempted DL shall mirror those adopted for recovery of the Regulatory Asset in D.03-07-028 and D.04-02-062.
>
> PG&E proposes to continue the methods prescribed by Ordering Paragraph 65, but in a manner consistent with the requirements of Senate Bill (SB) 772 and the Public Utilities Code. Specifically, to the extent the Commission determines that the $0.027 per kWh cap on the CRS is appropriate for any group of DL customers, and if the full amount of the energy recovery bond charges are recoverable under the cap, that capped amount shall include recovery of the following components in the following order: (1) DWR Bond Charge; (2) Energy Cost Recovery Amount (the amount of energy recovery bond charges specified in Ordering Paragraph 65); (3) Ongoing Competition Transition Charges (CTC); and (4) DWR Power Charges. In the remote event that the energy recovery bond charges could not be recovered from all responsible customers under the 2.7 cent CRS cap, PG&E proposes to adjust the rates in these instances such that the energy recovery bond charge is fully

recovered from all responsible customers on a timely basis without deferral.

Any shortfall that results from applying a cap to the CRS will be attributed only to the CRS component that is not fully recovered. The shortfalls resulting from the capping will then be recovered only from those DL customers that are required to pay the particular CRS component that was not fully recovered due to action of the cap. As a result, customers that are not required to pay ERB will not be required to pay ERB shortfalls. Only non-exempt capped customers are responsible for the respective shortfalls.

The Settling Parties agree to this outcome for Rate Design issue 3.16.

Because the impact of the ERB Settlement is shown in the referenced PG&E testimony, and ORA is not a settling party, no further comparison exhibit is required by Rule 51.1(c).

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

The Settling Parties further agree that this ERB Settlement will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.04-06-024. 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 ERB Settlement or the May 13 Settlement.

V. ERB 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

ERB Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the ERB Settlement as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this ERB Settlement on behalf of the Settling Parties they represent.

This ERB Settlement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Settling Party represented.

Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: Counsel

Pacific Gas and Electric Company

By: _____

Title: _____

ERB Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the ERB Settlement as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this ERB Settlement on behalf of the Settling Parties they represent.

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Cogeneration Association of California and Energy Producers and Users Coalition

By: _____

Title: _____

Pacific Gas and Electric Company

By: _____

Title: Attorney

(END OF APPENDIX G)