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

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design, including Real Time Pricing, to Revise its Customer Energy Statements, and to Seek Recovery of Incremental Expenditures. (U 39 M)	Application 10-03-014 (Filed March 22, 2010)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION

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SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in Application (A.) 10-03-014, "Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design" (commonly referred to as Phase 2 of PG&E's 2011 General Rate Case).[1/] The details of this Settlement Agreement are set forth herein.

This Settlement is a direct result of Administrative Law Judge Pulsifer and Assigned Commissioner Peevey's encouragement to the active parties to meet and seek a workable compromise. The active parties held differing views on numerous aspects of PG&E's initial marginal cost and revenue allocation proposals in Phase 2 of this GRC proceeding. However,

1/ The residential rate design proposals in A.10-03-014 have already been litigated and briefed. Such residential rate design issues, which have been submitted to the CPUC for decision, are not the subject of this Settlement Agreement. Similarly, proposals within A.10-03-014 for Real Time Pricing, to Revise PG&E's Customer Energy Statements, and to Seek Recovery of Incremental Expenditures (commonly referred to as Phase 3 of A.10-03-014) will be considered on a separate track from Phase 2 issues, and are also not the subject of this Settlement Agreement.

the Parties bargained earnestly and in good faith to seek a compromise and to develop this Settlement, which is the product of arms-length negotiations among the Settling Parties on a number of disputed issues. These negotiations considered the interests of all of the active parties on marginal cost and revenue allocation issues, and the Settlement addresses each of these interests in a fair and balanced manner.

The Settling Parties crafted this Settlement by agreeing to concessions and trade-offs among themselves. Thus the various elements and sections of this Settlement are intimately interrelated, and should not be altered as the Settling Parties intend that the Settlement be treated as a package solution which strives to balance and align the interests of each party. Accordingly, the Settling Parties respectfully request that the Commission promptly approve the Settlement without modification. Any material change to the Settlement shall render it null and void, unless all of the Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows:

- Agricultural Energy Consumers Association (AECA)
- California City-County Street Light Association (CAL-SLA)
- California Farm Bureau Federation (CFBF)
- California Large Energy Consumers Association (CLECA)
- California Manufacturers & Technology Association (CMTA)
- Direct Access Customer Coalition (DACC)
- Division of Ratepayer Advocates (DRA)
- Energy Producers and Users Coalition (EPUC)
- Energy Users Forum (EUF)
- Federal Executive Agencies (FEA)
- Pacific Gas and Electric Company (PG&E)
- South San Joaquin Irrigation District (SSJID)
- The Utility Reform Network (TURN)
- Western Manufactured Housing Communities Association (WMA)

III. SETTLEMENT CONDITIONS

This Settlement Agreement resolves the issues raised by the Settling Parties in A.10-03-014 (Phase 2), on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the Settlement only to arrive at the agreement embodied herein. Nothing contained in the Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding. For example, this Settlement does not preclude any party taking a position for or against the question of whether pensions and benefits associated with energy efficiency, low income energy efficiency, and the CARE program should be reassigned from distribution to public purpose program costs in any future proceeding where the level of those program costs are at issue.
4. The Settling Parties agree that this Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.
5. The Settling Parties agree that no provision of this Settlement Agreement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that this Settlement Agreement addresses all marginal

cost and revenue allocation issues except the specific marginal costs to be used solely for the purpose of establishing unit costs where needed for customer specific contract rate floors for customer retention and attraction. The Settling Parties agree this issue will be addressed in subsequent settlement discussions.

7. This Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this Settlement Agreement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required,[2/] briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.
9. The Settling Parties intend the Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement Agreement, the Settling Parties reserve their rights under Rule 12.4 of the CPUC's Rules of Practice and Procedure, and the Settlement should not be admitted into evidence in this or any other proceeding.

IV. OVERALL PROCEDURAL HISTORY

In its Test Year 2011 General Rate Case (GRC) Application 09-12-020, PG&E stated that electric marginal cost data, revenue allocation, and rate design proposals would be filed in Phase 2 of the 2011 GRC. The March 5, 2010 Assigned Commissioner's Ruling and Scoping Memo in A.09-12-020 (March 5, 2010 ACR) directed PG&E to file its marginal costs, revenue allocation, and rate design proposals in a separate application.

Consistent with the March 5, 2010 ACR, PG&E filed Application 10-03-014 on March 22, 2010, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended

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2/ Any oral and written testimony that the CPUC might require may be prepared jointly among parties with similar interests.

to "continue toward the key objectives of (1) redesigning electric rates to more closely align with cost-causation principles; and (2) simplifying electric rates and tariffs to make them easier for customers to understand…." and "to continue the movement of electric rates closer to cost of service, while also taking into consideration equity among customers and customer acceptance." (A.10-03-014, page 3.) The application was protested on April 26, 2010, by DRA, TURN, Disability Rights Advocates (DisabRA), Vote Solar, Solar Alliance, and SSJID.

A prehearing conference was held in the proceeding on May 19, 2010, before Administrative Law Judge (ALJ) Pulsifer. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 26, 2010 (Scoping Memo). The Scoping Memo ruled that "[t]his proceeding shall be conducted in two separate phases, (i.e., Phases 2 and 3 of PG&E's 2011 GRC, respectively). The scope of Phase 2 shall encompass PG&E's proposals relating to electric marginal costs, revenue allocation, and rate design, and other parties responsive testimony and recommendations on those issues."[3/]

In a ruling issued October 20, 2010, ALJ Pulsifer set residential rate design issues for hearing in November 2010, and deferred hearings for marginal costs, revenue allocation and non-residential rate design until a date to be set in a subsequent ruling, to be issued no earlier than January 17, 2011. Parties served testimony on residential rate design issues on or about October 6, 2010 and rebuttal testimony on or about October 29, 2010. Residential rate design hearings were held from November 12 to November 22, 2010. The residential rate design portion of the case was submitted on January 10, 2011 for Commission decision, upon completion of briefing.

DRA served prepared testimony on September 8, 2010. On October 6, 2010, intervenors AECA, CAL-SLA, CFBF, CLECA, CMTA, City and County of San Francisco, DACC, DisabRA, EPUC, FEA, the Greenling Institute, the City of Hercules, County of Kern, Kern County Taxpayers Association, the Lamont Public Utility District, The Marin Energy Authority,

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3/ This ruling went on to define the scope of Phase 3 of the proceeding to "consider PG&E's proposals relating to dynamic pricing and revisions to its customer energy statement" as agreed among PG&E, DRA, and TURN in their Joint Prehearing Conference Statement filed on May 19, 2010.

Sierra Club, Solar Alliance, SSJID, TURN, Vote Solar and WMA served their prepared testimony. Of those filing, AECA, CAL-SLA, CFBF, CLECA, CMTA, DACC, EPUC, FEA, the City of Hercules, the Lamont Public Utility District, Solar Alliance, SSJID, TURN and WMA provided testimony on marginal costs, revenue allocation and rate design that were not the subject of the residential rate design portion of Phase 2.

Pursuant to ALJ Pulsifer's December 8, 2010 procedural ruling, PG&E updated its showing on marginal costs, revenue allocation and non-residential rate design[4/] on January 7, 2011. Also, pursuant to ALJ Pulsifer's December 8, 2010 ruling, parties will have the opportunity to serve prepared testimony on PG&E's January 7, 2011 updated testimony. Pursuant to ALJ Pulsifer's February 25, 2011 procedural ruling, the service date for parties' rebuttal testimony is April 29, 2011, with surrebuttal testimony due May 20, 2011.

V. SETTLEMENT HISTORY

On August 11, 2010, PG&E sent a notice under Rule 12 of a settlement conference to be held October 5, 2010. Pursuant to ALJ Pulsifer's ruling of September 29, 2010, the date of the settlement conference was moved to October 13, 2010. Notice of the revised settlement conference date was served on September 30, 2010. On October 13, 2010, the parties began to conduct settlement discussions on revenue allocation, marginal cost and non-residential rate design issues in Phase 2 with the active parties to the proceeding, pursuant to Article 12 of the CPUC's rules. As reflected in the status reports filed by PG&E, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated December 8, 2010 and January 19, 2011.

During the week of January 31, 2011, parties to the settlement discussions reached an agreement in principle on the terms of this Settlement Agreement. In the February 18, 2011 status report, PG&E's counsel notified ALJ Pulsifer that the active parties to the proceeding had reached settlement in principle regarding marginal cost and revenue allocation-related issues, and

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4/ Certain very limited residential rate design-related issues are still pending as they were not the subject of the November 2010 hearings (*see* Exhibit PG&E-14, Chapter 3, served on January 7, 2011). (*See also* footnote 5, infra.)

requested a further extension of the procedural schedule to memorialize the settlement and continue their efforts to reach agreement on other non-residential rate design issues. ALJ Pulsifer granted the request by written ruling dated February 25, 2011.

VI. SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of determining marginal costs in this proceeding is to establish a basis for allocating generation and distribution revenue among rate groups.

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this Settlement Agreement. The revenue allocation amounts, percentages and procedures agreed to in this Settlement Agreement better align customer class average rates with customer class costs of service.

No later than April 15, 2011, PG&E and DRA will jointly serve a comparison exhibit showing the impact of the Settlement Agreement in relation to their respective litigation positions, as required by Rules 12.1(a).

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

The Settling Parties further agree that this Settlement Agreement will be followed by the Settling Parties' efforts to reach agreement on additional issues in A.10-03-014 on non-residential rate design issues that are not resolved by this Settlement Agreement.[5/] To the extent all issues are not settled, the Settling Parties agree to pursue litigation in this proceeding on those issues only, provided those issues do not affect the outcome of issues agreed upon in this Settlement Agreement.

5/ PG&E expects settlement discussions in the areas of (1) small commercial rate design, (2) medium and large commercial and industrial rate design (including Standby), (3) agricultural rate design, (4) streetlight rate design, and (5) limited residential rate design issues not previously addressed. If and as settlements are reached on such rate design issues, they would be submitted as supplements to this Settlement, as was done in PG&E's 2007 GRC Phase 2 proceeding.

VII. MARGINAL COSTS SETTLEMENT

This Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below. The Settling Parties agree that this Settlement Agreement addresses all marginal cost issues except the specific marginal costs to be used solely for the purpose of establishing unit costs where needed for customer specific contract rate floors for customer retention and attraction. The Settling Parties agree this issue will be addressed in subsequent settlement discussions. Nothing in this Settlement shall preclude any Settling Party from advocating for their preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this proceeding.

If the Commission adopts new marginal costs/methodologies, the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the Settlement Agreement revenue allocation.

VIII. REVENUE ALLOCATION SETTLEMENT

1. Agreed-Upon Allocation Principles for the Initial Allocation

The Settling Parties agree that electric revenue should be allocated as a result of A.10-03-014 on an overall revenue-neutral basis to preserve then-current total authorized revenue. The Settling Parties agree to the initial revenue allocation implemented as a result of this proceeding as set forth in the following Table 1. Table 1 shows the current average electric rates as of preparation of this Settlement, the average electric rate that results from the Settlement, and the percentage change for both direct access/community choice aggregation customers and bundled customers. The Settling Parties agree that PG&E will target the average percentage change for every customer group shown in Table 1, but the actual results may vary somewhat based on rate changes that may occur before this Settlement Agreement is implemented. The Settling Parties agree as follows:

a. Revenue allocation results as shown in Table 1 establish the basis for the initial allocation resulting from this proceeding.

b. There is no agreement on marginal costs for purposes of revenue allocation, although for the initial allocation the Settling Parties agree to use PG&E's latest updated marginal cost, as provided in its January 7, 2011 Update in Phase 2 of its 2011 GRC, as the starting point for the mechanical calculations described in Part f, below.

c. There is no change to the allocation of nuclear decommissioning, the DWR bond charge, the Energy Costs Recovery Amount or the Competition Transition Charge.

d. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

e. Public Purpose Program (PPP) rates will be developed as the sum of public purpose program components:

   1. The cost of the CARE discount will be determined based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the California Solar Initiative cost, and the DWR bond charge. This cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This iterative determination of the CARE surcharge is described in paragraph f. 3, below.

   2. There is no change to the methodology for allocation of revenues for the remaining public purpose program components for the initial allocation.

f. After the allocations of all the revenues described above have been determined, PG&E will seek to create the bundled and direct access percentage changes agreed to in this proceeding by adjustment of distribution and generation revenue. PG&E will take the following steps:

   1. Set the residential rate design assumptions to include all residential rate design initiatives proposed by PG&E in Exhibit PG&E-8, Chapter 3, except that instead of PG&E's proposed customer charge, the minimum

charge is assumed.

2. Use the percentage movement toward generation and distribution full equal percent of marginal cost revenue[6/] which were used to derive the settlement results: Generation 50 percent and Distribution 35 percent. Apply the same absolute dollar adjustments to each customer group as used to achieve the Settlement results (see Table 2). Should the adjustments not yield a result sufficiently close to the desired percentage changes, PG&E may adjust the percentage movement toward distribution and generation full equal percent of marginal cost revenue[7/] and the absolute dollar adjustments as necessary to achieve the desired result.

3. Revise residential rate design assumptions to those approved by the Commission on residential rate design in A.10-03-014 and recalculate the allocation of the CARE surcharge revenue among customer groups. The first step to revising the allocation of the CARE surcharge is to set the residential CARE rates and the residential non-CARE Tier 1 and Tier 2 rates as required by Commission decision and/or SB 695. The rate/s for non-CARE usage in excess of Tier 2 are then set to collect the remaining residential class allocation of costs before any reallocation of revenue. Based on the change to the level of CARE and non-CARE rates, the amount of the CARE discount is recalculated and the CARE surcharge is derived. The revised CARE surcharge changes the allocation to all non-CARE customers, changing the allocation of costs among non-CARE customer groups. Based on the reallocation of revenue to non-CARE residential customers, upper tier residential rates are recalculated. This change to residential non-CARE rates again changes the difference between CARE and non-CARE rates leading to a change in the discount. Based on the revised discount, the CARE surcharge is recalculated. This cycle of calculations is iterative and is repeated until the funding of the CARE discount exactly offsets the discounts provided to CARE

6/ For purposes of this Settlement Agreement, the Settling Parties used PG&E's proposed marginal costs from its January 7, 2011 Update in Phase 2 of its 2011 GRC to perform these calculations.

7/ *See* footnote 6 above.

customers. As a result of final adopted residential rate design and reallocation of revenue due to the revised CARE surcharge, the final percentage changes will vary from those shown in Table 1.

Table 1
Pacific Gas and Electric Company Phase 2
Settlement Revenue Allocation Results – Initial Year

	Present 1/1/11 Rates	Proposed Rates	% Change
Bundled			
Total Residential	15.658	15.740	0.5%
Non CARE Residential	18.233	18.040	-1.1%
Total Small Commercial	17.831	17.877	0.3%
A-10 Transmission	12.427	11.802	-5.0%
A-10 Primary	14.523	14.368	-1.1%
A-10 Secondary	15.828	15.678	-0.9%
Total A-10	15.819	15.669	-0.9%
E-19 Transmission	11.225	10.801	-3.8%
E-19 Primary	12.556	12.375	-1.4%
E-19 Secondary	13.807	13.657	-1.1%
Total E-19	13.701	13.548	-1.1%
Streetlights	16.268	16.513	1.5%
Standby Transmission	11.108	10.726	-3.4%
Standby Primary	21.519	22.595	5.0%
Standby Secondary	20.877	21.576	3.3%
Total Standby	12.014	11.750	-2.2%
Total Agriculture	14.581	14.800	1.5%
E-20 Transmission	9.631	9.365	-2.8%
E-20 Primary	12.014	11.894	-1.0%
E-20 Secondary	13.253	12.992	-2.0%
Total E-20	11.496	11.297	-1.7%
Bundled Total	15.062	15.049	-0.1%
Direct Access/Community Choice			
Total Residential	14.246	15.151	6.4%
Total Small Commercial	11.367	11.217	-1.3%
A-10 Primary	8.388	9.001	7.3%
A-10 Secondary	7.898	7.933	0.4%
Total A-10	7.900	7.936	0.5%
E-19 Primary	8.240	8.652	5.0%
E-19 Secondary	6.447	6.493	0.7%
Total E-19	6.529	6.591	0.9%
Standby Transmission	8.010	7.658	-4.4%
Total Agriculture	7.898	7.880	-0.2%
E-20 Transmission	3.519	3.573	1.5%
E-20 Primary	5.179	5.417	4.6%
E-20 Secondary	6.287	6.267	-0.3%
Total E-20	4.826	4.955	2.7%
Direct Access/Community Choice Total	5.869	5.968	1.7%

Table 2
Pacific Gas and Electric Company Phase 2
Settlement Revenue Allocation Adjustments – Initial Year

	Generation Adjustment	Distribution Adjustment
Total Residential		$5,238,500
Non CARE Residential		$5,238,500
Total Small Commercial		($4,000,000)
A-10 Transmission		
A-10 Primary		($135,000)
A-10 Secondary	$19,062,000	$1,193,000
E-19 Transmission		
E-19 Primary		($1,394,000)
E-19 Secondary		$5,434,500
Streetlights		$1,140,000
Standby Transmission		
Standby Primary		($339,000)
Standby Secondary		
Total Agriculture	($15,408,000)	($4,092,000)
E-20 Transmission	($1,650,000)	
E-20 Primary		($2,960,000)
E-20 Secondary	($2,004,000)	($86,000)

2. Timing of the Initial Rate Change

If the rate change pursuant to this Settlement Agreement occurs in 2011, it shall be based on the sales forecast adopted in the 2011 Energy Resource Recovery Account (ERRA) forecast proceeding in Decision 10-12-007 (in A.10-05-022). If the rate change pursuant to this Settlement Agreement is not implemented until January 1, 2012, the rate change on January 1, 2012 will be conducted in two steps: (1) allocation pursuant to this agreement based on the 2011 sales forecast; and then (2) allocation of revised revenue requirements pursuant to the 2012 Annual Electric True-Up (AET), based on the 2012 sales forecast and the guidelines set forth in Section 3 below regarding Rate Changes Between General Rate Cases. If the rate change implementing this Settlement Agreement does not occur until after January 1, 2012, PG&E will incorporate the Settlement into rates based on then-current rates and the 2012 sales forecast. PG&E will then consult with the Settlement Parties prior to implementation to ensure the Settling Parties agree that the benefits of the Settling Agreement are preserved.

3. Rate Changes Between General Rate Cases

After rates are implemented pursuant to the Settlement Agreement and the Commission's decision in A.10-03-014, rates will be changed to reflect changes in the revenue requirement in the manner set forth below:

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

b. Generation revenue developed to determine the appropriate starting point to apply the percentages from Section 3.a., above, will exclude non-allocated revenue (for generation revenue, other standby revenue). In addition, for the rate changes where there is a change to Competition Transition Charges (CTC), current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice. In addition, generation adjustments will be made for Peak Time Rebate and Peak Day Pricing as approved by the Commission.[8/] These adjustments will be accomplished by excluding the adjustment revenue from the generation allocation, allocating the remaining revenue based on then current generation allocation methods, and then assigning the adjustment revenue directly to the class as necessary.

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

d. Distribution revenue developed to determine the appropriate starting point to apply the percentages from Section 3.a. above will exclude non-allocated revenue (for distribution revenue, non-allocated revenue includes, but is not limited to, other standby revenue, E-BIP discounts, streetlight facilities charges, meter charges, employee discounts, retention and attraction discounts, and the Schedule A-15 facilities charge) as well as estimated California Alternate Rates for Energy (CARE)

8/ Generation adjustments for Peak Day Pricing, as required by D.10-02-032, will be deducted from the generation revenue to be allocated. The remaining revenue will be allocated based on the then-current rules in place for generation revenue, and the amount of the adjustment will be directly assigned by customer class. Similar adjustments will be made for Peak Time Rebate if required by the Commission in PG&E's 2010 Rate Design Window proceeding (A.10-01-028).

program discounts. In addition, a special adjustment will be calculated for the change in each of the following program revenues:

1. The electric revenue requirement for 28 percent of the Advanced Meter Infrastructure/SmartMeter™ Balancing Account[9/];
2. The electric revenue requirement for Customer Energy Efficiency Incentive Account (CEEIA);
3. The revenue requirement for Demand Response costs as set forth for recovery in the Demand Response Revenue Balancing Account (DRRBA);
4. The revenue requirement for the Air Conditioning Expenditures Balancing Account;
5. The revenue requirement for the Dynamic Pricing Memorandum Account (DPMA) as transferred from DPMA to the Distribution Revenue Adjustment Mechanism (DRAM) for recovery; and
6. The revenue requirement for the California Solar Initiative (CSI).

The adjustment will be for the change in the revenue relative to last authorized amount. In each case, the change in the revenue will be determined as the then-current authorized amount less the forecast system average rate for the program from the prior year (based on the last authorized revenue requirement) multiplied by the then-current forecast of applicable sales for the test year. The total adjustment so determined, either positive or negative, will be deducted from (in the case of an increase) or added to (in the case of a reduction) the authorized distribution amount, and the remaining distribution revenue will be allocated based on the standard rules for allocation of distribution revenue. As a final step, the amount of the adjustment will be directly assigned to each customer group based on the allocation factors provided in Table 3.

9/ The remaining 72 percent of the revenue requirement for the AMI/SmartMeter™ Balancing Account will be allocated in the same manner as other distribution revenue.

Table 3
Pacific Gas and Electric Company Phase 2
Settlement Revenue Allocation Adjustments – Initial Year

Customer Class	Allocation Percentage
Residential Class	44.0%
Small Light and Power Class	14.5%
All Others	41.5%
Total	100%

Within the "All Others" subgroup listed in Table 3, the adjustment shall be allocated to rate classes and schedules based on the standard rules for allocating distribution revenue as set forth in this paragraph. Within the Small Light and Power subgroup, the adjustment will be allocated as an equal percentage change to distribution revenue for each rate schedule and an equal percentage change to energy charges as necessary to collect the schedule level revenue. Within the Residential subgroup, the adjustment shall be collected in distribution energy charges consistent with SB 695 and the upcoming decision on residential rate design in this case.

e. Public Purpose Program (PPP) rates will be developed as the sum of three pieces and will be allocated as follows:

1. The cost of the CARE program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the CSI and the DWR Bond charge. The cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This iterative determination of the CARE surcharge is described in paragraph VIII, 1. f. 3, above.

2. The cost of the Low Income Energy Efficiency and Procurement Energy Efficiency will be allocated to customers based on an equal percent of the sum of then-current Low Income Energy Efficiency and Procurement Energy Efficiency revenue (that is, the same percentage will be applied to the then-current revenue for each customer group to determine the allocated revenue).
3. PG&E will continue its current practice of allocating revenues for Energy Efficiency, Renewables and Research, Development and Demonstration projects based on the rate cap established in Public Utilities Code Section 399.8 (Exhibit PG&E-14, Chapter 2, Part C).

f. Non-residential rate changes will be implemented as equal percentage changes to demand and energy charges by component as necessary to collect the assigned revenue. Customer charges, streetlighting facilities charges, meter charges and minimum charges will be unchanged between general rate cases,[10/] unless specified in this 2011 GRC Phase 2, or revised by a separate Commission decision (for example, a PG&E Rate Design Window proceeding).

g. The DWR Bond charge shall continue to be collected on an equal cents per kWh basis.

h. The Energy Cost Recovery Amount shall continue to be allocated and collected among eligible customers on an equal cents per kWh basis.

i. Nuclear Decommissioning costs shall continue to be allocated and collected among eligible customers on an equal cents per kWh basis.

j. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

k. Once initially approved in response to PG&E's Advice Letter 3524-E, PG&E will continue to make non-allocated adjustments for the Distribution Bypass Deferral Rate Memorandum Account (DBDRMA) in its AET filings. These adjustments would be accomplished as proposed in Advice Letter 3524-E, dated September 15, 2009, or as otherwise approved by the Commission in response to PG&E's Advice Letter. Specifically, PG&E proposed that it would make these adjustments by: excluding the

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

balance in the DBDRMA from the allocation of proposed revenue; allocating the remaining revenue requirements based on the applicable revenue allocation and rate design methods in effect at the time; and then directly assigning the balance in the DBDRMA to all customers except residential customers, and customers served on Schedules A-1, A-6 and A-15.[11/]

l. The costs of the Family Electric Rate Assistance (FERA) program will continue to be assigned to the residential class in the year after they are incurred. Administrative costs and CSI discounts will continue to be recovered in residential distribution rates and Tier 3 discounts will continue to be recovered in residential generation rates.

m. Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2011 GRC Phase 2 and the 2014 GRC Phase 2 decisions, the Settling Parties agree that the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and that the rules governing existing revenue requirement categories presented in this settlement will not govern or be precedential for that purpose. Parties will be free to advocate whatever position the party deems appropriate for the new revenue requirement cost category at the time it is under consideration by the Commission.

4. Other Allocations Issues

The Settling Parties agree to PG&E's proposed disposition of balances in the Common Area Balancing Account (CABA) and the Baseline Balancing Account (BBA) as presented in Exhibit PG&E-14, Chapter 1, Section J (2). Specifically, once the CPUC completes the Headroom Audit associated with its review of the Headroom Calculation filed in Advice 2555-G/2521-E, and has concluded that PG&E has properly recovered its costs and has set rates properly beginning in 2004, the balances in CABA and BBA will be eliminated with no adjustment to rates going forward. Should the Commission determine that rates were not set at the proper levels beginning in 2004, the allocation of any necessary revenue adjustments among customers will be decided by the Commission.

11/ *See* Exhibit PG&E-14, Chapter 1, Section I.

IX. DATA AND MODELING WORKSHOPS FOR 2014 GRC PHASE 2

1. Marginal Generation Capacity Costs and Marginal Energy Costs

The Settling Parties agree that PG&E will hold a workshop for parties to its 2011 GRC Phase 2 proceeding prior to filing its 2014 GRC Phase 2 (GRC Phase 2) application, for the purpose of discussing the marginal generation cost data and methodologies that might be used in GRC Phase 2 to develop marginal costs. The workshop will be set for a date at least 10 months before the scheduled filing date of PG&E's 2014 GRC Phase 2 application under the Rate Case Plan (i.e., prior to May 1, 2012). Additional follow-up workshops may be scheduled, if warranted. This workshop schedule is based on a scheduled filing date of March 2013 for Phase 2 of the 2014 GRC, and could be modified if the Commission significantly revises the filing date.

One purpose of the workshop would be to discuss publicly available data sources that may be appropriate to use for marginal cost purposes in GRC Phase 2. The discussion would include publicly available data sources, such as the CAISO Market Redesign Technology Upgrade (MRTU) day-ahead price data, adjustments required based on factors such as gas prices or weather (as examples), and appropriate use(s) of the data in GRC Phase 2, such as for energy price shaping (as an example). The use of non-public data sources, such as third party proprietary broker quotes, may also be discussed, but the confidential, proprietary data itself will not be provided and the confidential status and treatment of that data, such as the broker quotes, will not change.

A second purpose of the workshop would be to discuss possible means for making modeling for marginal costs in GRC Phase 2 more transparent. Such workshop discussion would identify portions of PG&E's modeling that use transparent and publicly available data that are not confidential. The workshop would also identify portions of PG&E's modeling that involve sensitive confidential data, such as the gross margin modeling, and explore possible development of a transparent modeling approach instead of confidential modeling, such as for gross margins, using non-confidential data that produces reasonable results solely for use in PG&E's GRC Phase 2.

A third purpose of the workshop would be to discuss the financial and operating characteristics data sources potentially used in the modeling of marginal generation costs. Examples of such data would include, without limitation: heat rates, variable Operation and Maintenance (O&M), costs per start, installed costs of generating units, and possible sources for this type of data.

A fourth purpose of the workshop would be to discuss developments that may provide guidance with respect to modeling marginal generation capacity costs and energy costs. An example, without limitation, may be the Integrated Demand Side Management working group's review of the cost effectiveness analysis performed for Energy Efficiency, Distributed Generation, Demand Response, Storage and AMI in order to develop a whitepaper and guidance for modeling to evaluate cost effectiveness of integrated demand side programs.

The goal of the workshop would be to improve the transparency of data and methodologies, and identify areas of analyses which would produce reasonable marginal generation capacity costs and marginal energy cost estimates, while minimizing use of confidential, proprietary data and modeling. Examples of workshop topics include, without limitation:

a. The use of historic CAISO MRTU NP15 day ahead prices (CAISO DAM) for the shaping of the marginal energy costs and its possible basis in the preparation of the gross margin adjustment;

b. Any adjustments that may be made to the CAISO DAM prices to ensure that the resulting shapes and prices are reasonable;

c. Identification and discussion of the data sources that would provide an annual forecast of energy prices that would be subject to shaping;

d. The methods of translating the hourly energy prices into TOU periods;

e. The structure of the marginal generation capacity cost model (MGCC);

f. The operating characteristics and financial data inputs that are used in the MGCC for calculating the going forward fixed costs and the gross margin, and the data sources for those inputs. This would include discussions of capital cost by generating unit, heat rates, start-up costs, O&M, discount factors, insurance costs, etc.;

g. The possible use of a production simulation model to model gross margin as opposed to a stochastic modeling and the data and data sources that might be used;

h. An exchange of ideas on ways to quantify ancillary services and renewable resource adders into the modeling of marginal energy and capacity costs in addition to discussing the possible incorporation of working capital and fuel inventory into the analysis;

i. The basis (e.g. data, regulatory proceedings) for identifying PG&E's year-of-need for new generation purposes of modeling the MGCC; and

j. The identification, preparation, and sharing of possible data/information in advance of PG&E's filing that would assist parties in the preparation of their showings.

By conducting and participating in the workshop(s), neither PG&E nor any party would be committing to the use or production of specific data, data source(s), calculation(s), modeling, or specific guidance. The Settling Parties agree that they will each need to review data, information, calculations, methodologies, then-current market conditions, and other information presented at the workshop prior to determining whether they could agree to any specific calculations or methodology for determining marginal generation or energy costs for PG&E's 2014 GRC Phase 2. Nothing in this Settlement would preclude PG&E or any other Settling Party from objecting to data requests propounded in any proceeding, or limit the grounds for the objections. Nothing in this Settlement would preclude PG&E or any other Settling Party from opposing the use of data, methodology, or modeling in any party's testimony, or limit the grounds for opposing use of data, methodology, or modeling in any party's testimony.

2. Marginal Distribution Capacity Costs and Marginal Customer Access Costs

The Settling Parties agree that PG&E will hold a workshop for the parties to its 2011 GRC Phase 2 prior to filing its 2014 GRC Phase 2 (GRC Phase 2) application for the purpose of discussing data for marginal distribution capacity costs and marginal customer access costs that might be used in GRC Phase 2 to develop marginal costs. The workshop would also discuss methodologies as well as potential model simplification and transparency. The workshop will be set for a date at least 10 months before the scheduled filing date for PG&E's 2014 GRC Phase 2 application under the Rate Case Plan (i.e. prior to May 1, 2012). Additional follow-up workshops may be scheduled, if warranted. This workshop schedule is based on a scheduled filing date of March 2013 for Phase 2 of the 2014 GRC, and could be modified if the Commission significantly revises the filing date.

The Settling Parties support the twin goals of: (1) model simplification (e.g. reducing the number of linked files and structural changes to improve transparency of inputs versus calculation and results) and (2) use of data that makes marginal cost analyses easier without sacrificing accuracy. The Settling Parties recognize that steps to serve these goals are subject to reasonable availability of data and modeling without undue cost and demand on resources.

Data requested by parties for PG&E's 2014 GRC Phase 2 proceeding, and which PG&E anticipates it will be able to provide, include:

a. Customer Data – Forecast and five years of recorded numbers of new customer by class, schedule and service voltage.

b. Cost Data – Marginal customer costs, stated with the following characteristics:

   1. Marginal cost using dollars-per-customer as the cost unit;

   2. Marginal cost separated out by class recognizing:

      (a) Differences in customer size (demand and/or usage); and

      (b) Differences in metering requirements (e.g. secondary, primary or transmission service voltage, usage-only or usage and demand metering).

c. Cost Data – Customer access equipment capital cost data, with the following characteristics:

1. Differentiation by class;
2. Differentiation by overhead and underground access equipment installations;
3. Differentiation of residential costs by single-family and multi-family installations;
4. Provide treatment of multi-customer jobs and number of customers involved; and
5. Distinguish between single-phase and poly-phase jobs for the small light and power class (in addition to the agricultural classes).

The parties have requested the following data for the 2014 GRC Phase 2 proceeding, but further investigation and analysis is required by PG&E before PG&E can determine whether the data could be provided. At or before the workshop, PG&E will report on whether or not the data in the following list can be provided.

a. Customer Data – A record of new customers by class, schedule and service voltage by division or distribution Planning Area (DPA).
b. Cost Data – Marginal customer costs, stated with the following characteristics:
    1. Distinguish costs of transformers from services (as well as meters);
    2. Transparent costs of transformers by class and rate schedule, particularly for non-residential classes, tied to job contract cost data; and
    3. Distinguish between numbers of streetlight accounts and number of streetlights.
c. Equipment replacement cost data that includes unit costs of actual historical service replacements using same categories as for PG&E's 2007 GRC new services.
d. O&M costs for customer service drops in total and as allocated by class.

By conducting and participating in the workshop(s), neither PG&E nor any other Settling Party would be committing to use or production of specific data, data sources(s), calculations(s), modeling, or specific guidance. The Settling Parties agree that they will need to review data, information, calculations, methodologies, then-current market conditions, and other information presented at the workshop prior to determining whether they can agree to any specific calculations or methodology for determining marginal distribution capacity costs or marginal customers access costs for 2014 GRC Phase 2. Customer-specific information will be aggregated as is required to protect confidential information about individual customers. Nothing in this Settlement would preclude PG&E or any other Settling Party from objecting to data requests propounded in any proceeding, or limit the grounds for the objections. Nothing in this Settlement would preclude PG&E or any other Settling Party from opposing the use of data, methodology or modeling in any party's testimony, or limit the grounds for opposing use of data, methodology or modeling in any party's testimony.

3. Revenue Allocation

The Settling Parties agree that PG&E will hold workshops for parties to its 2011 GRC Phase 2 prior to filing its 2014 GRC Phase 2 (GR Phase 2) application for the purpose of discussing data and modeling for revenue allocation that might be used to develop positions in GRC Phase 2. The workshops would also discuss methodologies, and potential model simplification and transparency. Two workshops will be held. The first workshop will be scheduled in the first quarter of 2012, followed by a second workshop scheduled in the second quarter of 2012. The scheduling of these workshops is based on a scheduled filing date of March 2013 for Phase 2 of the 2014 GRC, and could be modified if the Commission significantly revises the filing date. Additional workshops may be scheduled if warranted.

a. PG&E agrees to provide the following information as part of its next GRC Phase 2 filing:

   1. Recorded system level billing determinant information used to estimate forecast billing determinants;
   2. A roadmap and users guide for the revenue allocation model;

3. A revenue allocation model that is capable of producing alternative revenue allocation results for miscellaneous revenue;
4. A revenue allocation model that is capable of producing alternative revenue allocation results for different marginal costs scenarios; and
5. A revenue allocation model that presents the distribution and generation equal percent of marginal cost multiplier for generation and distribution on a summary page.

b. The Settling Parties agree that the 2012 workshop(s) will include discussions on the following issues:
   1. PG&E's review of alternative approaches to determining the CARE discount as part of the revenue allocation model;
   2. PG&E's review of alternative approaches to class level capping as part of the revenue allocation model;
   3. PG&E's proposed approach to revising the revenue allocation model to provide alternative revenue allocation results for miscellaneous revenue and marginal costs;
   4. The potential use of Advanced Meter Infrastructure (AMI) data to supplement or adjust the Class Load Research Population sample;
   5. Whether a study to establish the extent to which customer generation creates diversity on PG&E's distribution system is warranted; and
   6. PG&E's proposed approach for simplifying the revenue allocation model including, but not limited to:

      (a) Uniformity of formats (i.e., output of the marginal cost model should have the same format as the input to the revenue allocation model);

      (b) Reduced number of separate files;

      (c) Minimal duplication of information;

      (d) Use of color coding; and

(e) Toggles with clearly defined options.

X. SETTLEMENT EXECUTION

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

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(END OF APPENDIX A)

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SUPPLEMENTAL SETTLEMENT AGREEMENT ON MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Medium and Large Light and Power (MLLP) Rate Design Settlement Agreement (MLLP Settling Parties) agree on a mutually acceptable outcome to the rate design issues for the MLLP class[1] in Application (A.) 10-03-014, Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.[2]

This MLLP Settlement is supplemental to the Settlement in A. 10-03-014 filed with the CPUC on March 14, 2011 (March 14 Settlement), in that it uses the revenue allocation agreed to in the March 14 Settlement and addresses MLLP issues that were not resolved in the March 14 Settlement. The MLLP Settling Parties have also reached agreement on the marginal costs to be used for discounted price floors for use with Schedules ED, E-31 or special contracts, which was referenced but not resolved in the March 14 Settlement. The MLLP Settling Parties respectfully request that the Commission consolidate its decision on this MLLP Settlement with its decision on the March 14 Settlement because the instant MLLP Settlement is an extension of and is complementary to the March 14 Settlement Agreement. The details of this MLLP Settlement are set forth herein.

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1 The MLLP customer classes encompass and are defined as: Schedules A-10, A-10 TOU, E-19V, Mandatory E-19, E-20, and Standby, as described in Exhibit PGE-14 Chapter 5.

2 The Small Light and Power (SLP) rate design issues in this proceeding are being resolved under a separate supplemental SLP Settlement Agreement.

II. MLLP SETTLING PARTIES

The MLLP Settling Parties are as follows:

- California Large Energy Consumers Association (CLECA)
- California Manufacturers & Technology Association (CMTA)
- Division of Ratepayer Advocates
- Energy Producers and Users Coalition (EPUC)
- Energy Users Forum (EUF)
- Federal Executive Agencies (FEA)
- Pacific Gas and Electric Company (PG&E)

III. MLLP SETTLEMENT CONDITIONS

This MLLP Settlement resolves the issues raised by the MLLP Settling Parties in A.10-03-014 on MLLP rate design, subject to the conditions set forth below:

1. This MLLP Settlement embodies the entire understanding and agreement of the MLLP Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the MLLP Settling Parties with respect to those matters.. This supplement/extension to the March 14 settlement filing incorporates by reference the terms and boilerplate language of that document.

2. This MLLP Settlement represents a negotiated compromise among the MLLP Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of this Settlement only to arrive at the agreement embodied herein. Nothing contained in this MLLP Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the MLLP Settling Parties on these matters in this proceeding. Pursuant to Rule 12 of the

Commission's Rules of Practice and Procedure, this MLLP Settlement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.

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

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

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

6. The MLLP Settling Parties shall jointly request Commission approval of this MLLP Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required,[3] briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The MLLP Settling Parties intend the MLLP Settlement to be interpreted and treated as a unified, integrated agreement incorporating the March 14 Settlement, which forms the foundation for the MLLP rate design agreed to herein. In the event the Commission rejects or modifies this MLLP Settlement or the underlying

[3] Any oral and written testimony that the CPUC might require may be prepared jointly among parties with similar interests.

March 14 Settlement, the MLLP Settling Parties reserve their rights under CPUC Rule 12.4.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The overall procedural and settlement history of A.10-03-14 is set forth in Section IV of the March 14, 2011 Settlement on marginal cost and revenue allocation issues in this proceeding. This supplement/extension to the March 14 Settlement filing incorporates by reference the terms, boilerplate and all other language in that document.

V. MLLP SETTLEMENT TERMS

A. General Terms

The MLLP Settling Parties agree that the primary purpose of rate design for the MLLP classes is to take the revenue allocations reached for those classes in the March 14 Settlement and ensure that they are fully recovered through MLLP rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the March 14 Settlement, and reflects a reasonable compromise of Settling Parties' proposals.

The MLLP Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Tables 1 and 2 of the March 14 Settlement, which were based on the January 1, 2011 effective rates and revenue requirements. The MLLP Settling Parties agree that the actual rates derived at the time of implementation of this MLLP Settlement, once adopted by the CPUC, shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the MLLP classes. Adopted revenue requirements in effect at the time of settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates that will result when the Phase 2 rate changes are implemented will vary from those shown in Exhibit A. However, these actual rates shall be based on the rate design methods described in this MLLP Settlement Agreement.

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

The MLLP Settling Parties further agree that this MLLP Settlement resolves all MLLP rate design issues in A.10-03-014.

B. MLLP Settlement Rates

1. Illustrative Settlement Rates

The MLLP Settling Parties agree that rates to collect the revenue allocated to the MLLP customer classes under the March 14 Settlement shall be designed consistent with the illustrative rates set forth below and in Exhibit A, for Schedules A-10, A-10 TOU, E-19V, Mandatory E-19, E-20, and Standby. Exhibit A includes updates to Standby customer charges to reflect the $10 single-phase and $20 polyphase customer charge levels agreed to in the SLP Settlement for Schedules A-1 and A-6.

The MLLP Settling Parties further agree that the methodologies underlying these agreed illustrative rates shall serve as a starting point for updating and determining the changes to rates necessary to collect the adopted revenue requirement in effect when this Settlement is implemented, as discussed in Section A of this Agreement, above.

2. Methods Used To Develop Illustrative Settlement Rates

The MLLP Settling Parties agree that the basic rate designs for each of the applicable MLLP rate schedules will be updated upon implementation of this settlement using the methods underlying development of the illustrative settlement rates for

Schedules A-10, A-10 TOU, E-19, E-20, and Standby set forth in this supplemental settlement agreement.

The MLLP Settling Parties understand and acknowledge that the SLP Settlement Agreement will include language establishing a kilowatt-based delineation, as well as a kWh proxy if needed, defining the boundaries between the SLP and MLP classes that will phase-in during this 2011 GRC cycle, as specified in the SLP Settlement Agreement.

Distribution component demand charge and (where applicable) energy charge principles to develop applicable illustrative unbundled and total rates as shown in Exhibit A are based upon PG&E's January 7, 2011 filed proposals, as updated to reflect the March 14 Settlement. Generation component demand and energy charges generally reflect PG&E's January 7, 2011 filed proposals, with the exception that E-19 and E-20 have been modified through settlement to assign a slightly higher share of generation capacity costs to demand charges, and to reshape energy charges to provide slightly greater time-of-use (TOU) differentiation than proposed by PG&E. These principles will be used or reasonably modified to achieve rate levels and rate relationships comparable to those shown in Exhibit A.

The above methods shall be used to set initial rates upon implementation of this Settlement at the then-current revenue requirements using settlement revenue allocation principles. All subsequent rate changes until the next GRC Phase 2 decision shall be governed by the principles set forth the March 14, 2011 Revenue Allocation Settlement Agreement, in Section VIII, 3a and 3f, for Rate Changes Between General Rate Cases.

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

The MLLP Settling Parties agree that PG&E's proposal to eliminate the summer season average rate limiters for Schedules E-19 and E-20 primary and secondary service is reasonable and should be adopted.

3. Schedule A-6 Solar Pilot

The MLLP Settling Parties agree that the Schedule A-6 Solar Pilot which allows large customers to take service on Schedule A-6, although they are otherwise not eligible to take service on Schedule A-6, should not be expanded. The Schedule A-6 Solar Pilot currently has a 20 MW cap on participating load. Although the MLLP Settling Parties do not agree that the cap should be increased, they do, however, agree that, if a current participant drops out, a new enrollment may be allowed to fill the pilot back up to the 20 MW cap level. The MLLP Settling Parties oppose the expansion of the A-6 Solar Pilot because doing so would create additional revenue shortfalls beyond those already caused by the current A-6 Solar Pilot with the 20 MW cap.

The MLLP Settling Parties further agree that a new Option R rate Schedule with reduced demand charges for solar customers should not be adopted. The MLLP Settling Parties oppose the creation of Option R because it would create even greater, additional revenue shortfalls above those already caused by the current A-6 Solar Pilot with the 20 MW cap.

The MLLP Settling Parties further agree that the 90-day opt-in period to participate in the A-6 Solar Pilot for existing Schedule E-19 customers is obsolete and should be eliminated.

4. Provisions Related to Standard Non-Firm Service Rates

The MLLP Settling Parties agree that Schedule E-BIP interruptible program discounts or incentive levels will be evaluated and decided in the 2012-2014 Demand Response proceeding (Application 11-03-001).

5. Peak Day Pricing Refinements

The MLLP Settling Parties agree that PG&E's proposal for Peak Day Pricing (PDP) refinements to Schedules A-10-TOU, E-19 and E-20, as proposed in Chapter 9 (PG&E-14), are reasonable and should be adopted.

6. Commercial Submetering Report

The MLLP Settling Parties agree that the report ordered in D.09-07-004 is unnecessary because no commercial master-metered buildings appear to have installed submetering systems to prorate the master-meter bills among tenants. Therefore, the MLLP Settling Parties agree that the requirement to produce the report should be eliminated.

7. Discounted Price Floors for Schedules ED and E-31

Discounted price floors for Schedules ED, E-31, or other discounted rates or special contracts will use (a) price floors based upon the average of the generation marginal energy costs adopted in the 2007 GRC Phase 2 in D.070-09-004 and the 2011 generation marginal energy costs presented in PG&E's January 7, 2011 GRC Phase 2 Update testimony, and (b) price floors based upon the updated transmission and distribution marginal costs and generation marginal capacity costs presented in PG&E's January 7, 2011 GRC Phase 2 Update testimony. The Settling Parties believe that this resolution best balances the interests of ratepayers in allowing PG&E to meet competing offers to retain or attract new business which, as designed, should reduce marginal costs for all customers, as traded off against the impact of such discounts on contribution to margin. Exhibit A contains the applicable elements comprising the Settlement price floors.

8. Other

Unless otherwise specifically agreed by the parties or addressed in this MLLP Settlement Agreement above, the proposals, methods and explanations contained in revenue allocation and rate design Exhibit PG&E-14, Chapter 5, served on January 7, 2011, shall be adopted for the purpose of implementing rates under this Settlement. Unless and until default TOU and default PDP D.10-02-032 is modified by the CPUC in response to the Petitions to Modify now pending, the MLLP Settling Parties' understanding is that the non-TOU A-10 rate is being retained only on an interim basis for those customers without 12 months of interval billing data, and once the trigger for those customers to default to TOU is reached, customers must take service on a TOU or PDP rate.

VI. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the March 14 Settlement, Term VIII. Subsections 2 and 3, shall apply to this MLLP Settlement, unless specifically noted above.

Certain elements of this MLLP Settlement Agreement will require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. These structural and system changes, which include the agreed elimination of the rate limiters for E-19 and E-20, as well as kW or kWh thresholds between the Small and Medium L&P customer classes, will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The MLLP Settling Parties recognize that these changes could take several months to implement.

VII. SETTLEMENT EXECUTION

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

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EXHIBIT A

ILLUSTRATIVE MLLP SETTLEMENT RATES

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

[See Attached Excel Spreadsheet and Word Document]

Exhibit A

ILLUSTRATIVE MLLP SETTLEMENT RATES

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

*Total revenues calculated here do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
A-10 Transmission						
DEMAND CHARGES ($/kW)						
Summer Max	1,058	$7.61	$8,054	1,058	$7.61	$8,057
Winter Max	1,454	$4.22	$6,134	1,454	$4.22	$6,129
Revenue from Demand Charges			$14,188			$14,186
Revenue from Demand as % of Total			16.1%			16.9%
ENERGY CHARGES ($/kWh)						
Summer	305,764	$0.11342	$34,680	305,764	$0.10375	$31,722
Winter	404,511	$0.08969	$36,281	404,511	$0.08474	$34,277
Revenue from Energy Charges			$70,960			$66,000
Revenue from Energy as % of Total			80.4%			78.7%
CUSTOMER CHARGE ($/meter/mo.)	26	$120.00	$3,120	26	$140.00	$3,640
Revenue from Customer Charges			$3,120			$3,640
Revenue from Customer as % of Total			3.5%			4.3%
TOTAL REVENUE			$88,269			$83,826
						-5.03%

*Total revenues do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
A-10 Primary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer Max	128,649	$10.09	$1,298,069	128,649	$11.19	$1,439,137
Winter Max	117,605	$6.16	$724,445	117,605	$5.85	$688,306
Revenue from Demand Charges			$2,022,514			$2,127,442
Revenue from Demand as % of Total			19.3%			20.5%
ENERGY CHARGES ($/kWh)						
Summer	36,937,367	$0.12905	$4,766,767	36,937,367	$0.12587	$4,649,336
Winter	35,022,691	$0.10027	$3,511,725	35,022,691	$0.09653	$3,380,733
Revenue from Energy Charges			$8,278,492			$8,030,069
Revenue from Energy as % of Total			79.0%			77.5%
CUSTOMER CHARGE ($/meter/mo.)	1,429	$120.00	$171,479	1,429	$140.00	$200,059
Revenue from Customer Charges			$171,479			$200,059
Revenue from Customer as % of Total			1.6%			1.9%
TOTAL REVENUE			$10,472,486			$10,357,570
						-1.10%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
A-10 Secondary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer Max	19,105,123	$10.78	$205,953,231	19,105,123	$11.86	$226,551,028
Winter Max	16,305,094	$6.71	$109,407,177	16,305,094	$5.68	$92,688,828
Revenue from Demand Charges			$315,360,409			$319,239,856
Revenue from Demand as % of Total			19.2%			19.6%
ENERGY CHARGES ($/kWh)						
Summer	5,545,074,343	$0.13578	$752,910,194	5,545,074,343	$0.13418	$744,061,742
Winter	4,812,207,925	$0.10538	$507,110,471	4,812,207,925	$0.10085	$485,332,188
Revenue from Energy Charges			$1,260,020,665			$1,229,393,930
Revenue from Energy as % of Total			76.8%			75.6%
CUSTOMER CHARGE ($/meter/mo.)	549,849	$120.00	$65,981,848	549,849	$140.00	$76,978,823
Revenue from Customer Charges			$65,981,848			$76,978,823
Revenue from Customer as % of Total			4.0%			4.7%
TOTAL REVENUE			$1,641,362,922			$1,625,612,609
						-0.96%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
A-10 TOU Transmission	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer Max	1,058	$7.61	$8,054	1,058	$7.61	$8,057
Winter Max	1,454	$4.22	$6,134	1,454	$4.22	$6,129
Revenue from Demand Charges			$14,188			$14,186
Revenue from Demand as % of Total			16.1%			16.9%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	80,762	$0.13065	$10,552	80,762	$0.11377	$9,188
Part-Peak	77,037	$0.11370	$8,759	77,037	$0.10987	$8,464
Off-Peak	147,964	$0.10359	$15,328	147,964	$0.09509	$14,070
Winter						
Part-Peak	197,233	$0.09325	$18,392	197,233	$0.09075	$17,898
Off-Peak	207,279	$0.08627	$17,882	207,279	$0.07902	$16,379
Revenue from Energy Charges			$70,912			$66,000
Revenue from Energy as % of Total			80.4%			78.7%
CUSTOMER CHARGE ($/meter/mo.)	26	$120.00	$3,120	26	$140.00	$3,640
Revenue from Customer Charges			$3,120			$3,640
Revenue from Customer as % of Total			3.5%			4.3%
TOTAL REVENUE			$88,221			$83,826
						-4.98%

*Total revenues do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
A-10 TOU Primary						
DEMAND CHARGES ($/kW)						
Summer Max	128,649	$10.09	$1,298,069	128,649	$11.19	$1,439,137
Winter Max	117,605	$6.16	$724,445	117,605	$5.85	$688,306
Revenue from Demand Charges			$2,022,514			$2,127,442
Revenue from Demand as % of Total			19.3%			20.5%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	9,756,371	$0.14683	$1,432,528	9,756,371	$0.13682	$1,334,843
Part-Peak	9,306,384	$0.12953	$1,205,456	9,306,384	$0.13259	$1,233,894
Off-Peak	17,874,611	$0.11880	$2,123,504	17,874,611	$0.11640	$2,080,599
Winter						
Part-Peak	17,076,459	$0.10398	$1,775,610	17,076,459	$0.10303	$1,759,350
Off-Peak	17,946,233	$0.09669	$1,735,221	17,946,233	$0.09035	$1,621,382
Revenue from Energy Charges			$8,272,319			$8,030,069
Revenue from Energy as % of Total			79.0%			77.5%
CUSTOMER CHARGE ($/meter/mo.)	1,429	$120.00	$171,479	1,429	$140.00	$200,059
Revenue from Customer Charges			$171,479			$200,059
Revenue from Customer as % of Total			1.6%			1.9%
TOTAL REVENUE			$10,466,313			$10,357,570
						-1.04%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
A-10 TOU Secondary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer Max	19,105,123	$10.78	$205,953,231	19,105,123	$11.86	$226,551,028
Winter Max	16,305,094	$6.71	$109,407,177	16,305,094	$5.68	$92,688,828
Revenue from Demand Charges			$315,360,409			$319,239,856
Revenue from Demand as % of Total			19.2%			19.6%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	1,464,636,172	$0.15545	$227,677,693	1,464,636,172	$0.14726	$215,688,416
Part-Peak	1,397,083,693	$0.13604	$190,059,266	1,397,083,693	$0.14134	$197,457,886
Off-Peak	2,683,354,478	$0.12448	$334,023,965	2,683,354,478	$0.12332	$330,915,440
Winter						
Part-Peak	2,346,349,387	$0.11005	$258,215,750	2,346,349,387	$0.10877	$255,223,988
Off-Peak	2,465,858,539	$0.10077	$248,484,565	2,465,858,539	$0.09332	$230,108,201
Revenue from Energy Charges			$1,258,461,239			$1,229,393,930
Revenue from Energy as % of Total			76.7%			75.6%
CUSTOMER CHARGE ($/meter/mo.)	549,849	$120.00	$65,981,848	549,849	$140.00	$76,978,823
Revenue from Customer Charges			$65,981,848			$76,978,823
Revenue from Customer as % of Total			4.0%			4.7%
TOTAL REVENUE			$1,639,803,496			$1,625,612,609
						-0.87%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
E-19 Transmission						
DEMAND CHARGES ($/kW)						
Summer						
Peak	35,190	$7.88	$277,297	35,190	$12.51	$440,355
Part-Peak	36,398	$1.78	$64,789	36,398	$2.77	$100,943
Max	37,190	$5.94	$220,908	37,190	$4.99	$185,567
Winter						
Part-Peak	39,757	$0.00	$0	39,757	$0.00	$0
Max	41,750	$5.94	$247,992	41,750	$4.99	$208,319
Revenue from Demand Charges			$810,986			$935,185
Revenue from Demand as % of Total			24.7%			29.6%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	2,786,635	$0.10714	$298,560	2,786,635	$0.08867	$247,096
Part-Peak	3,193,929	$0.08818	$281,641	3,193,929	$0.07407	$236,585
Off-Peak	8,389,467	$0.07684	$644,647	8,389,467	$0.06509	$546,053
Winter						
Part-Peak	5,873,741	$0.08130	$477,535	5,873,741	$0.07346	$431,504
Off-Peak	8,691,614	$0.07347	$638,573	8,691,614	$0.06635	$576,659
Revenue from Energy Charges			$2,340,955			$2,037,897
Revenue from Energy as % of Total			71.4%			64.6%
AVERAGE RATE LIMITER		NA			NA	
CUSTOMER CHARGE ($/meter/mo.)						
E-19	90	$1,200.00	$108,000	90	$1,800.00	$162,000
Rate V	148	$125.40	$18,559	148	$140.00	$20,720
Revenue from Customer Charges			$126,559			$182,720
Revenue from Customer as % of Total			3.9%			5.8%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$3,278,500			$3,155,802 -3.74%

*Total revenues do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
E-19 Primary						
DEMAND CHARGES ($/kW)						
Summer						
Peak	803,136	$10.93	$8,778,279	803,136	$14.15	$11,368,313
Part-Peak	937,861	$2.53	$2,372,788	937,861	$3.04	$2,852,592
Max	890,320	$7.78	$6,926,689	890,320	$9.09	$8,095,133
Winter						
Part-Peak	923,889	$0.94	$868,455	923,889	$0.36	$329,022
Max	943,874	$7.78	$7,343,341	943,874	$9.09	$8,582,069
Revenue from Demand Charges			$26,289,552			$31,227,128
Revenue from Demand as % of Total			26.5%			32.1%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	85,364,387	$0.14358	$12,256,619	85,364,387	$0.12268	$10,472,911
Part-Peak	96,187,593	$0.09981	$9,600,484	96,187,593	$0.08854	$8,516,612
Off-Peak	233,900,050	$0.08108	$18,964,616	233,900,050	$0.06819	$15,950,506
Winter						
Part-Peak	157,129,025	$0.08742	$13,736,219	157,129,025	$0.08469	$13,306,854
Off-Peak	213,353,826	$0.07786	$16,611,729	213,353,826	$0.07063	$15,069,088
Revenue from Energy Charges			$71,169,667			$63,315,970
Revenue from Energy as % of Total			71.7%			65.0%
AVERAGE RATE LIMITER		$0.23455			NA	
CUSTOMER CHARGE ($/meter/mo.)						
E-19	2,544	$600.00	$1,526,691	2,544	$1,000.00	$2,544,485
Rate V	2,182	$125.40	$273,602	2,182	$140.00	$305,456
Revenue from Customer Charges			$1,800,293			$2,849,942
Revenue from Customer as % of Total			1.8%			2.9%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$99,259,512			$97,393,041
						-1.88%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
E-19 Secondary						
DEMAND CHARGES ($/kW)						
Summer						
Peak	11,080,106	$12.21	$135,288,090	11,080,106	$14.34	$158,868,750
Part-Peak	11,170,729	$2.84	$31,724,871	11,170,729	$3.32	$37,055,775
Max	11,906,333	$9.00	$107,156,998	11,906,333	$11.56	$137,676,545
Winter						
Part-Peak	10,199,770	$1.25	$12,749,712	10,199,770	$0.19	$1,969,449
Max	10,415,179	$9.00	$93,736,608	10,415,179	$11.56	$120,433,873
Revenue from Demand Charges			$380,656,279			$456,004,392
Revenue from Demand as % of Total			29.8%			36.3%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	1,036,673,042	$0.14473	$150,037,689	1,036,673,042	$0.13327	$138,152,645
Part-Peak	1,121,315,562	$0.10206	$114,441,466	1,121,315,562	$0.09387	$105,254,907
Off-Peak	2,682,566,174	$0.08477	$227,401,135	2,682,566,174	$0.06808	$182,630,471
Winter						
Part-Peak	1,869,570,218	$0.09216	$172,299,591	1,869,570,218	$0.08865	$165,736,822
Off-Peak	2,482,838,305	$0.08239	$204,561,048	2,482,838,305	$0.07103	$176,357,643
Revenue from Energy Charges			$868,740,930			$768,132,486
Revenue from Energy as % of Total			68.1%			61.1%
AVERAGE RATE LIMITER		$0.23455			NA	
CUSTOMER CHARGE ($/meter/mo.)						
E-19	18,530	$412.50	$7,643,479	18,530	$600.00	$11,117,787
Rate V	154,708	$125.40	$19,400,351	154,708	$140.00	$21,659,085
Revenue from Customer Charges			$27,043,830			$32,776,872
Revenue from Customer as % of Total			2.1%			2.6%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$1,276,441,039			$1,256,913,750 -1.53%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

E-20 Transmission	JANUARY 1, 2011 RATES Billing Determinants	Rates	Revenue	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer						
Peak	3,422,225	$9.55	$32,682,245	3,422,225	$12.41	$42,468,352
Part-Peak	3,760,277	$2.14	$8,046,994	3,760,277	$2.69	$10,111,842
Max	4,145,644	$4.22	$17,494,619	4,145,644	$4.14	$17,144,964
Winter						
Part-Peak	3,582,203	$0.00	$0	3,582,203	$0.00	$0
Max	3,730,242	$4.22	$15,741,620	3,730,242	$4.14	$15,427,002
Revenue from Demand Charges			$73,965,477			$85,152,160
Revenue from Demand as % of Total			22.6%			26.8%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	317,941,524	$0.09975	$31,714,667	317,941,524	$0.08843	$28,114,506
Part-Peak	378,514,171	$0.08216	$31,098,724	378,514,171	$0.07382	$27,943,322
Off-Peak	1,044,474,963	$0.07167	$74,857,521	1,044,474,963	$0.06191	$64,663,738
Winter						
Part-Peak	642,476,796	$0.07579	$48,693,316	642,476,796	$0.07501	$48,190,120
Off-Peak	938,654,437	$0.06855	$64,344,762	938,654,437	$0.06504	$61,054,007
Revenue from Energy Charges			$250,708,990			$229,965,693
Revenue from Energy as % of Total			76.7%			72.3%
AVERAGE RATE LIMITER		NA			NA	
CUSTOMER CHARGE ($/meter/mo.)	1,473	$1,500.00	$2,209,208	1,473	$2,000.00	$2,945,611
Revenue from Customer Charges			$2,209,208			$2,945,611
Revenue from Customer as % of Total			0.7%			0.9%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$326,883,675			$318,063,464
						-2.70%

*Total revenues do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
E-20 Primary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer						
Peak	4,789,454	$11.04	$52,875,576	4,789,454	$13.73	$65,767,813
Part-Peak	5,018,322	$2.59	$12,997,454	5,018,322	$2.90	$14,534,152
Max	5,221,168	$7.45	$38,897,700	5,221,168	$9.07	$47,379,629
Winter						
Part-Peak	4,656,619	$0.82	$3,818,427	4,656,619	$0.23	$1,082,265
Max	4,729,209	$7.45	$35,232,605	4,729,209	$9.07	$42,915,334
Revenue from Demand Charges			$143,821,762			$171,679,193
Revenue from Demand as % of Total			26.0%			31.4%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	468,707,292	$0.14040	$65,806,504	468,707,292	$0.12211	$57,231,939
Part-Peak	538,988,157	$0.09807	$52,858,569	538,988,157	$0.08836	$47,627,196
Off-Peak	1,390,998,186	$0.07992	$111,168,575	1,390,998,186	$0.06849	$95,263,371
Winter						
Part-Peak	897,982,816	$0.08585	$77,091,825	897,982,816	$0.08459	$75,960,747
Off-Peak	1,273,252,537	$0.07664	$97,582,074	1,273,252,537	$0.07167	$91,250,018
Revenue from Energy Charges			$404,507,547			$367,333,271
Revenue from Energy as % of Total			73.1%			67.2%
AVERAGE RATE LIMITER		$0.22782			NA	
CUSTOMER CHARGE ($/meter/mo.)	5,292	$1,000.00	$5,292,252	5,292	$1,500.00	$7,938,377
Revenue from Customer Charges			$5,292,252			$7,938,377
Revenue from Customer as % of Total			1.0%			1.5%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$553,621,560			$546,950,841 -1.20%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

E-20 Secondary	JANUARY 1, 2011 RATES Billing Determinants	Rates	Revenue	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT Billing Determinants	Rates	Revenue
DEMAND CHARGES ($/kW)						
Summer						
Peak	2,568,133	$11.88	$30,509,421	2,568,133	$14.00	$35,956,871
Part-Peak	2,607,429	$2.67	$6,961,836	2,607,429	$3.07	$8,000,254
Max	2,716,776	$8.97	$24,369,481	2,716,776	$11.34	$30,794,930
Winter						
Part-Peak	2,450,160	$1.24	$3,038,198	2,450,160	$0.21	$524,989
Max	2,475,475	$8.97	$22,205,012	2,475,475	$11.34	$28,059,761
Revenue from Demand Charges			$87,083,948			$103,336,805
Revenue from Demand as % of Total			30.0%			36.5%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	255,263,925	$0.13854	$35,364,264	255,263,925	$0.12268	$31,315,913
Part-Peak	262,661,584	$0.09851	$25,874,793	262,661,584	$0.08951	$23,511,911
Off-Peak	617,196,317	$0.08217	$50,715,021	617,196,317	$0.06764	$41,746,712
Winter						
Part-Peak	467,015,270	$0.08926	$41,685,783	467,015,270	$0.08479	$39,600,108
Off-Peak	575,888,541	$0.07992	$46,025,012	575,888,541	$0.06852	$39,460,891
Revenue from Energy Charges			$199,664,873			$175,635,536
Revenue from Energy as % of Total			68.9%			62.0%
AVERAGE RATE LIMITER		$0.22782			NA	
CUSTOMER CHARGE ($/meter/mo.)	4,251	$750.00	$3,188,207	4,251	$1,000.00	$4,250,943
Revenue from Customer Charges			$3,188,207			$4,250,943
Revenue from Customer as % of Total			1.1%			1.5%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
TOTAL REVENUE			$289,937,029			$283,223,284
						-2.32%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
Standby Transmission						
RESERVATION CHARGES ($/kW)						
(Rates applicable to 85%*Contract Capacity)						
Summer Contract Capacity	3,584,365	$0.90	$2,742,039	3,584,365	$0.89	$2,697,128
Winter Contract Capacity	3,584,365	$0.90	$2,742,039	3,584,365	$0.89	$2,697,128
Revenue from Reservation Charges			$5,484,078			$5,394,257
Revenue from Reservation as % of Total			15.6%			15.9%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	20,384,802	$0.10756	$2,192,589	20,384,802	$0.09369	$1,909,780
Part-Peak	23,405,181	$0.09342	$2,186,512	23,405,181	$0.09002	$2,106,944
Off-Peak	104,869,477	$0.08500	$8,913,906	104,869,477	$0.07610	$7,980,153
Winter						
Part-Peak	65,014,000	$0.08831	$5,741,386	65,014,000	$0.08861	$5,761,106
Off-Peak	107,108,471	$0.08247	$8,833,236	107,108,471	$0.07757	$8,308,180
Revenue from Energy Charges			$27,867,629			$26,066,163
Revenue from Energy as % of Total			79.3%			76.9%
CUSTOMER CHARGE ($/meter/mo.)						
Small-Single Phase (A-6)	(0)	$9.00	($0)	(0)	$10.00	($0)
Small-Polyphase (A-6)	(0)	$13.50	($0)	(0)	$20.00	($0)
Medium (>50kW & <500kW)	22	$120.00	$2,592	22	$140.00	$3,024
Medium (>500kW & <1000kW)	396	$1,200.00	$475,200	396	$1,800.00	$712,800
Large (>1000kW)	857	$1,500.00	$1,285,500	857	$2,000.00	$1,714,000
Reduced - Small (<50kW)		$11.90	$0		$14.61	$0
Reduced - Medium (>50kW & <500kW)	86	$57.32	$4,952	86	$76.43	$6,604
Reduced - Medium (>500kW & <1000kW)		$851.00	$0		$1,232.15	$0
Revenue from Customer Charges			$1,768,244			$2,436,428
Revenue from Customer as % of Total			5.0%			7.2%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)		$0.35			$0.35	
TOTAL REVENUE			$35,119,951			$33,896,847
						-3.48%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue

*Total revenues do not include E-BIP discounts, ED discounts, E-CARE discounts, rate limiter shortfall revenue (applicable to present revenue only), power factor revenue, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
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	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
Standby Primary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
RESERVATION CHARGES ($/kW)						
(Rates applicable to 85%*Contract Capacity)						
Summer Contract Capacity	223,088	$2.72	$515,780	223,088	$2.99	$566,815
Winter Contract Capacity	223,088	$2.72	$515,780	223,088	$2.99	$566,815
Revenue from Reservation Charges			$1,031,560			$1,133,630
Revenue from Reservation as % of Total			24.09%			25.19%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	1,859,816	$0.29595	$550,412	1,859,816	$0.41599	$773,658
Part-Peak	1,465,616	$0.17908	$262,463	1,465,616	$0.22755	$333,501
Off-Peak	6,083,154	$0.13500	$821,226	6,083,154	$0.14940	$908,852
Winter						
Part-Peak	4,172,990	$0.15721	$656,036	4,172,990	$0.12362	$515,884
Off-Peak	6,375,607	$0.13274	$846,298	6,375,607	$0.10355	$660,218
Revenue from Energy Charges			$3,136,435			$3,192,114
Revenue from Energy as % of Total			73.23%			70.92%
CUSTOMER CHARGE ($/meter/mo.)						
Small-Single Phase (A-6)	0	$9.00	$0	0	$10.00	$0
Small-Polyphase (A-6)	0	$13.50	$0	0	$20.00	$0
Medium (>50kW & <500kW)	48	$120.00	$5,760	48	$140.00	$6,720
Medium (>500kW & <1000kW)	48	$600.00	$28,800	48	$1,000.00	$48,000
Large (>1000kW)	79	$1,000.00	$79,000	79	$1,500.00	$118,500
Reduced - Small (<50kW)		$11.90	$0		$14.61	$0
Reduced - Medium (>50kW & <500kW)	24	$57.32	$1,376	24	$76.43	$1,834
Reduced - Medium (>500kW & <1000kW)		$851.00	$0		$1,232.15	$0
Revenue from Customer Charges			$114,936			$175,054
Revenue from Customer as % of Total			2.68%			3.89%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)		$0.35			$0.35	
TOTAL REVENUE			$4,282,930			$4,500,798
						5.09%

PACIFIC GAS AND ELECTRIC COMPANY
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	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
Standby Secondary	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
RESERVATION CHARGES ($/kW)						
(Rates applicable to 85%*Contract Capacity)						
Summer Contract Capacity	116,459	$2.73	$270,243	116,459	$3.03	$299,577
Winter Contract Capacity	116,459	$2.73	$270,243	116,459	$3.03	$299,577
Revenue from Reservation Charges			$540,485			$599,154
Revenue from Reservation as % of Total			23.0%			24.6%
ENERGY CHARGES ($/kWh)						
Summer						
Peak	950,400	$0.30	$281,955	950,400	$0.41691	$396,231
Part-Peak	1,174,378	$0.18	$209,380	1,174,378	$0.22715	$266,756
Off-Peak	2,841,248	$0.13	$379,960	2,841,248	$0.14842	$421,705
Winter						
Part-Peak	2,588,368	$0.16	$408,212	2,588,368	$0.12439	$321,978
Off-Peak	3,852,150	$0.13	$506,442	3,852,150	$0.10257	$395,130
Revenue from Energy Charges			$1,785,949			$1,801,799
Revenue from Energy as % of Total			75.9%			74.0%
CUSTOMER CHARGE ($/meter/mo.)						
Small-Single Phase (A-6)	496	$9.00	$4,468	496	$10.00	$4,965
Small-Polyphase (A-6)	649	$13.50	$8,755	649	$20.00	$12,970
Medium (>50kW & <500kW)	12	$120.00	$1,440	12	$140.00	$1,680
Medium (>500kW & <1000kW)	24	$412.50	$9,900	24	$600.00	$14,400
Large (>1000kW)	0	$750.00	$0	0	$1,000.00	$0
Reduced - Small (<50kW)		$11.90	$0		$14.61	$0
Reduced - Medium (>50kW & <500kW)	12	$57.32	$688	12	$76.43	$917
Reduced - Medium (>500kW & <1000kW)		$851.00	$0		$1,232.15	$0
Revenue from Customer Charges			$25,251			$34,932
Revenue from Customer as % of Total			1.1%			1.4%
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		$0.00005			$0.00005	
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)		$0.35			$0.35	
TOTAL REVENUE			$2,351,685			$2,435,885
						3.58%

PACIFIC GAS AND ELECTRIC COMPANY
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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

	Dist	Gen	PPP	Other	Total
A-10 Transmission					
DEMAND CHARGES ($/kW)					
Summer Max	$0.39	$3.40		$3.83	$7.61
Winter Max	$0.39	$0.00		$3.83	$4.22
ENERGY CHARGES ($/kWh)					
Summer	$0.00205	$0.06902	$0.01445	$0.01823	$0.10375
Winter	$0.00205	$0.05001	$0.01445	$0.01823	$0.08474
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00
A-10 Primary					
DEMAND CHARGES ($/kW)					
Summer Max	$4.33	$3.02		$3.83	$11.19
Winter Max	$2.02	$0.00		$3.83	$5.85
ENERGY CHARGES ($/kWh)					
Summer	$0.02207	$0.07066	$0.01491	$0.01823	$0.12587
Winter	$0.01020	$0.05319	$0.01491	$0.01823	$0.09653
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

A-10 Secondary	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer Max	$4.83	$3.19		$3.83	$11.86
Winter Max	$1.85	$0.00		$3.83	$5.68
ENERGY CHARGES ($/kWh)					
Summer	$0.02461	$0.07614	$0.01521	$0.01823	$0.13418
Winter	$0.00937	$0.05805	$0.01521	$0.01823	$0.10085
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00

A-10 TOU Transmission	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer Max	$0.39	$3.40		$3.83	$7.61
Winter Max	$0.39	$0.00		$3.83	$4.22
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00205	$0.07904	$0.01445	$0.01823	$0.11377
Part-Peak	$0.00205	$0.07515	$0.01445	$0.01823	$0.10987
Off-Peak	$0.00205	$0.06036	$0.01445	$0.01823	$0.09509
Winter					
Part-Peak	$0.00205	$0.05602	$0.01445	$0.01823	$0.09075
Off-Peak	$0.00205	$0.04429	$0.01445	$0.01823	$0.07902
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

A-10 TOU Primary	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer Max	$4.33	$3.02		$3.83	$11.19
Winter Max	$2.02	$0.00		$3.83	$5.85
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.02207	$0.08161	$0.01491	$0.01823	$0.13682
Part-Peak	$0.02207	$0.07738	$0.01491	$0.01823	$0.13259
Off-Peak	$0.02207	$0.06119	$0.01491	$0.01823	$0.11640
Winter					
Part-Peak	$0.01020	$0.05969	$0.01491	$0.01823	$0.10303
Off-Peak	$0.01020	$0.04701	$0.01491	$0.01823	$0.09035
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00

A-10 TOU Secondary	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer Max	$4.83	$3.19		$3.83	$11.86
Winter Max	$1.85	$0.00		$3.83	$5.68
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.02461	$0.08922	$0.01521	$0.01823	$0.14726
Part-Peak	$0.02461	$0.08329	$0.01521	$0.01823	$0.14134
Off-Peak	$0.02461	$0.06528	$0.01521	$0.01823	$0.12332
Winter					
Part-Peak	$0.00937	$0.06597	$0.01521	$0.01823	$0.10877
Off-Peak	$0.00937	$0.05052	$0.01521	$0.01823	$0.09332
CUSTOMER CHARGE ($/meter/mo.)	$140.00				$140.00

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

E-19 Transmission	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$0.00	$12.51		$0.00	$12.51
Part-Peak	$0.00	$2.77		$0.00	$2.77
Max	$1.16	$0.00		$3.83	$4.99
Winter					
Part-Peak	$0.00	$0.00		$0.00	$0.00
Max	$1.16	$0.00		$3.83	$4.99
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.05800	$0.01363	$0.01705	$0.08867
Part-Peak	$0.00000	$0.04340	$0.01363	$0.01705	$0.07407
Off-Peak	$0.00000	$0.03441	$0.01363	$0.01705	$0.06509
Winter					
Part-Peak	$0.00000	$0.04279	$0.01363	$0.01705	$0.07346
Off-Peak	$0.00000	$0.03567	$0.01363	$0.01705	$0.06635
CUSTOMER CHARGE ($/meter/mo.)					
E-19	$1,800.00				$1,800.00
Rate V	$140.00				$140.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

E-19 Primary	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$3.81	$10.35		$0.00	$14.15
Part-Peak	$1.05	$2.00		$0.00	$3.04
Max	$5.26	$0.00		$3.83	$9.09
Winter					
Part-Peak	$0.36	$0.00		$0.00	$0.36
Max	$5.26	$0.00		$3.83	$9.09
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.09198	$0.01366	$0.01705	$0.12268
Part-Peak	$0.00000	$0.05784	$0.01366	$0.01705	$0.08854
Off-Peak	$0.00000	$0.03749	$0.01366	$0.01705	$0.06819
Winter					
Part-Peak	$0.00000	$0.05398	$0.01366	$0.01705	$0.08469
Off-Peak	$0.00000	$0.03992	$0.01366	$0.01705	$0.07063
CUSTOMER CHARGE ($/meter/mo.)					
E-19	$1,000.00				$1,000.00
Rate V	$140.00				$140.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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E-19 Secondary	Dist	Gen	PPP	Other	Total
	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT				
DEMAND CHARGES ($/kW)					
Summer					
Peak	$4.34	$10.00		$0.00	$14.34
Part-Peak	$1.17	$2.15		$0.00	$3.32
Max	$7.73	$0.00		$3.83	$11.56
Winter					
Part-Peak	$0.19	$0.00		$0.00	$0.19
Max	$7.73	$0.00		$3.83	$11.56
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.10168	$0.01454	$0.01705	$0.13327
Part-Peak	$0.00000	$0.06228	$0.01454	$0.01705	$0.09387
Off-Peak	$0.00000	$0.03649	$0.01454	$0.01705	$0.06808
Winter					
Part-Peak	$0.00000	$0.05706	$0.01454	$0.01705	$0.08865
Off-Peak	$0.00000	$0.03944	$0.01454	$0.01705	$0.07103
CUSTOMER CHARGE ($/meter/mo.)					
E-19	$600.00				$600.00
Rate V	$140.00				$140.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT				
	Dist	Gen	PPP	Other	Total
E-20 Transmission					
DEMAND CHARGES ($/kW)					
Summer					
Peak	$0.00	$12.41		$0.00	$12.41
Part-Peak	$0.00	$2.69		$0.00	$2.69
Max	$0.26	$0.00		$3.88	$4.14
Winter					
Part-Peak	$0.00	$0.00		$0.00	$0.00
Max	$0.26	$0.00		$3.88	$4.14
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.06093	$0.01179	$0.01571	$0.08843
Part-Peak	$0.00000	$0.04633	$0.01179	$0.01571	$0.07382
Off-Peak	$0.00000	$0.03441	$0.01179	$0.01571	$0.06191
Winter					
Part-Peak	$0.00000	$0.04751	$0.01179	$0.01571	$0.07501
Off-Peak	$0.00000	$0.03755	$0.01179	$0.01571	$0.06504
CUSTOMER CHARGE ($/meter/mo.)	$2,000.00				$2,000.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

E-20 Primary	Dist	Gen	PPP	Other	Total
DEMAND CHARGES ($/kW)					
Summer					
Peak	$4.15	$9.58		$0.00	$13.73
Part-Peak	$1.14	$1.75		$0.00	$2.90
Max	$5.19	$0.00		$3.88	$9.07
Winter					
Part-Peak	$0.23	$0.00		$0.00	$0.23
Max	$5.19	$0.00		$3.88	$9.07
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.09243	$0.01333	$0.01635	$0.12211
Part-Peak	$0.00000	$0.05869	$0.01333	$0.01635	$0.08836
Off-Peak	$0.00000	$0.03881	$0.01333	$0.01635	$0.06849
Winter					
Part-Peak	$0.00000	$0.05491	$0.01333	$0.01635	$0.08459
Off-Peak	$0.00000	$0.04199	$0.01333	$0.01635	$0.07167
CUSTOMER CHARGE ($/meter/mo.)	$1,500.00				$1,500.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT				
	Dist	Gen	PPP	Other	Total
E-20 Secondary					
DEMAND CHARGES ($/kW)					
Summer					
Peak	$4.16	$9.84		$0.00	$14.00
Part-Peak	$1.07	$2.00		$0.00	$3.07
Max	$7.46	$0.00		$3.88	$11.34
Winter					
Part-Peak	$0.21	$0.00		$0.00	$0.21
Max	$7.46	$0.00		$3.88	$11.34
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.09166	$0.01425	$0.01677	$0.12268
Part-Peak	$0.00000	$0.05850	$0.01425	$0.01677	$0.08951
Off-Peak	$0.00000	$0.03662	$0.01425	$0.01677	$0.06764
Winter					
Part-Peak	$0.00000	$0.05378	$0.01425	$0.01677	$0.08479
Off-Peak	$0.00000	$0.03751	$0.01425	$0.01677	$0.06852
CUSTOMER CHARGE ($/meter/mo.)	$1,000.00				$1,000.00
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

Standby Transmission	Dist	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
(Rates applicable to 85%*Contract Capacity)					
Summer Contract Capacity	$0.15	$0.27		$0.47	$0.89
Winter Contract Capacity	$0.15	$0.27		$0.47	$0.89
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.00000	$0.05783	$0.01368	$0.02218	$0.09369
Part-Peak	$0.00000	$0.05416	$0.01368	$0.02218	$0.09002
Off-Peak	$0.00000	$0.04024	$0.01368	$0.02218	$0.07610
Winter					
Part-Peak	$0.00000	$0.05276	$0.01368	$0.02218	$0.08861
Off-Peak	$0.00000	$0.04171	$0.01368	$0.02218	$0.07757
CUSTOMER CHARGE ($/meter/mo.)					
Small-Single Phase (A-6)	$10.00				$10.00
Small-Polyphase (A-6)	$20.00				$20.00
Medium (>50kW & <500kW)	$140.00				$140.00
Medium (>500kW & <1000kW)	$1,800.00				$1,800.00
Large (>1000kW)	$2,000.00				$2,000.00
Reduced - Small (<50kW)	$14.61				$14.61
Reduced - Medium (>50kW & <500kW)	$76.43				$76.43
Reduced - Medium (>500kW & <1000kW)	$1,232.15				$1,232.15
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	$0.35				$0.35

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	ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT				
Standby Primary	Dist	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
(Rates applicable to 85%*Contract Capacity)					
Summer Contract Capacity	$2.20	$0.32		$0.47	$2.99
Winter Contract Capacity	$2.20	$0.32		$0.47	$2.99
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.30674	$0.06830	$0.01877	$0.02218	$0.41599
Part-Peak	$0.12270	$0.06391	$0.01877	$0.02218	$0.22755
Off-Peak	$0.06135	$0.04711	$0.01877	$0.02218	$0.14940
Winter					
Part-Peak	$0.02073	$0.06195	$0.01877	$0.02218	$0.12362
Off-Peak	$0.01382	$0.04879	$0.01877	$0.02218	$0.10355
CUSTOMER CHARGE ($/meter/mo.)					
Small-Single Phase (A-6)	$10.00				$10.00
Small-Polyphase (A-6)	$20.00				$20.00
Medium (>50kW & <500kW)	$140.00				$140.00
Medium (>500kW & <1000kW)	$1,000.00				$1,000.00
Large (>1000kW)	$1,500.00				$1,500.00
Reduced - Small (<50kW)	$14.61				$14.61
Reduced - Medium (>50kW & <500kW)	$76.43				$76.43
Reduced - Medium (>500kW & <1000kW)	$1,232.15				$1,232.15
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	$0.35				$0.35

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ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

Standby Secondary	Dist	Gen	PPP	Other	Total
RESERVATION CHARGES ($/kW)					
(Rates applicable to 85%*Contract Capacity)					
Summer Contract Capacity	$2.20	$0.35		$0.47	$3.03
Winter Contract Capacity	$2.20	$0.35		$0.47	$3.03
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.30674	$0.07014	$0.01785	$0.02218	$0.41691
Part-Peak	$0.12270	$0.06442	$0.01785	$0.02218	$0.22715
Off-Peak	$0.06135	$0.04705	$0.01785	$0.02218	$0.14842
Winter					
Part-Peak	$0.02073	$0.06364	$0.01785	$0.02218	$0.12439
Off-Peak	$0.01382	$0.04873	$0.01785	$0.02218	$0.10257
CUSTOMER CHARGE ($/meter/mo.)					
Small-Single Phase (A-6)	$10.00				$10.00
Small-Polyphase (A-6)	$20.00				$20.00
Medium (>50kW & <500kW)	$140.00				$140.00
Medium (>500kW & <1000kW)	$600.00				$600.00
Large (>1000kW)	$1,000.00				$1,000.00
Reduced - Small (<50kW)	$14.61				$14.61
Reduced - Medium (>50kW & <500kW)	$76.43				$76.43
Reduced - Medium (>500kW & <1000kW)	$1,232.15				$1,232.15
POWER FACTOR ADJUSTMENT ($/KwH) per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%	$0.00005				$0.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	$0.35				$0.35

APPENDIX A

Marginal Costs For Use in PG&E Schedule ED and Schedule E31 Price Floors — Economic Development Load Attraction and Load Retention

TABLE 1: Marginal Generation Costs

Line No.	Voltage Level	Marginal Generation Capacity Cost ($/MW-YR)	Marginal Generation Energy Cost ($/kWh)				
			Summer			Winter	
			On Peak	Partial Peak	Off Peak	Partial Peak	Off Peak
1	Transmission	$ 91.73	$ 0.07234	$ 0.06137	$ 0.04979	$ 0.05736	$ 0.04875
2	Primary	94.75	0.07473	0.06333	0.05099	0.05890	0.04987
3	Secondary	99.34	0.07833	0.06517	0.05200	0.06178	0.05086

TABLE 2: Marginal Transmission Capacity Cost

Line No.	Marginal Transmission Capacity Cost ($/kW-Yr)
1	$ 19.29

TABLE 3: Marginal Customer Access Costs

Line No.	Customer Class	Marginal Customer Access Cost ($/Cust.-Yr)
1	Residential	$ 91.41
2	Agricultural A	505.69
3	Agricultural B	822.68
4	Small L & P	397.37
5	A10 Medium L & P Secondary	962.37
6	A10 Medium L & P Primary	1,642.34
7	E19 Secondary	9,251.70
8	E19 Primary	10,077.26
9	E19 Transmission	16,023.11
10	E20 Secondary	10,139.85
11	E20 Primary	11,921.28
12	E20 Transmission	23,991.51
13	Streetlights	139.08

TABLE 4: Marginal Distribution Capacity Costs by Division[1]

Line No.	Division	Marginal Dist. Cap. Costs — Substation (PCAF) Loads ($/PCAF-kW/Yr) Primary	New Business – Primary	Secondary	PCAF to FLT Load Adjustment Factor*	Marginal Dist. Cap. Costs — Final Line Transformer Loads ($/FLT-kW/Yr) New Business – Primary	Secondary
1	Central Coast	$ 80.22	$ 25.97	$ 3.63	50.83%	$ 13.20	$ 1.85
2	De Anza	32.53	11.60	0.94	54.75%	6.35	0.51
3	Diablo	80.27	21.73	1.79	56.16%	12.20	1.00
4	East Bay	41.15	34.38	1.79	44.90%	15.44	0.80
5	Fresno	58.09	18.12	1.44	42.25%	7.66	0.61
6	Kern	47.72	16.22	1.45	45.51%	7.38	0.66
7	Los Padres	94.39	32.75	1.74	40.23%	13.17	0.70
8	Mission	40.62	25.89	1.26	55.00%	14.24	0.69
9	North Bay	66.52	38.26	1.47	47.70%	18.25	0.70
10	North Coast	60.84	34.07	1.86	45.34%	15.45	0.84
11	North Valley	49.24	34.69	1.39	44.25%	15.35	0.61
12	Peninsula	54.16	11.48	1.64	50.69%	5.82	0.83
13	Sacramento	59.20	19.42	1.19	52.66%	10.23	0.63
14	San Francisco	23.32	15.58	0.77	50.84%	7.92	0.39
15	San Jose	50.66	14.29	1.12	57.40%	8.21	0.64
16	Sierra	77.22	22.72	3.07	49.36%	11.22	1.52
17	Stockton	47.94	20.41	1.09	50.71%	10.35	0.55
18	Yosemite	55.50	28.44	2.23	41.04%	11.67	0.91
19	System	54.86	21.09	1.59	48.61%	10.25	0.77

(END OF APPENDIX B)

[1] Utilizes Distribution Planning Area-specific inputs from PG&E's Workpapers supporting Exhibit (PG&E-15), Chapter 6, at pages WP6-5 – WP6-10, for PG&E's January 7, 2011, Update to Prepared Testimony.

SUPPLEMENTAL SETTLEMENT AGREEMENT ON SMALL LIGHT AND POWER RATE DESIGN ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Small Light and Power (SLP) Rate Design Settlement Agreement (SLP Settling Parties) agree on a mutually acceptable outcome to the rate design issues for the SLP class[1] in Application (A.) 10-03-014, of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.[2]

This SLP Settlement is supplemental to the Settlement in A.10-03-014 filed with the CPUC on March 14, 2011 (March 14 Settlement), in that it uses the revenue allocation agreed to in the March 14 Settlement and addresses SLP issues that were not resolved in the March 14 Settlement. The SLP Settling Parties respectfully request that the Commission consolidate its decision on this SLP Settlement with its decision on the March 14 Settlement because the instant SLP is an extension of and is complementary to the March 14 Settlement Agreement. The details of this SLP Settlement are set forth herein.

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1 The SLP customer class encompasses and is defined as PG&E customers taking service under Schedules A-1, A-1-TOU (Time-of-Use), A-6, A-15, TC-1and E-CARE, as described in Exhibit PG&E-14 Chapter 4.

2 The Medium and Large Light and Power (MLLP) rate design issues in this proceeding are being resolved under a separate supplemental MLLP Settlement Agreement.

II. SLP SETTLING PARTIES

The SLP Settling Parties are as follows:

- California City-County Street Light Association (CAL-SLA)
- Division of Ratepayer Advocates (DRA)
- Pacific Gas and Electric Company (PG&E)
- The Utility Reform Network

III. SLP SETTLEMENT CONDITIONS

This SLP Settlement resolves the issues raised by the SLP Settling Parties in A.10-03-014 on SLP rate design, subject to the conditions set forth below:

1. This SLP Settlement embodies the entire understanding and agreement of the SLP Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the SLP Settling Parties with respect to those matters. This SLP supplement/extension to the March 14 settlement filing incorporates by reference the terms, boilerplate and all language of that document.

2. This SLP Settlement represents a negotiated compromise among the SLP Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of this Settlement only to arrive at the agreement embodied herein. Nothing contained in this SLP Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the SLP Settling Parties on these matters in this proceeding. Pursuant to Rule 12 of the Commission's Rules of Practice and

Procedure, this SLP Settlement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.

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

4. The SLP 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 SLP Settling Parties.

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

7. The SLP Settling Parties intend the SLP Settlement to be interpreted and treated as a unified, integrated agreement incorporating the March 14 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 March 14 Settlement, the SLP Settling Parties reserve their rights under CPUC Rule 12.4.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The overall procedural and settlement history of A.10-03-014 is set forth in Section IV of the March 14, 2011 settlement on marginal cost and revenue allocation issues in this proceeding. This supplement/extension to the March 14 settlement filing incorporates by reference the terms and boilerplate language of that document.

V. SLP SETTLEMENT TERMS

A. General Terms

The SLP Settling Parties agree that the primary purpose of rate design for the SLP class is to take the revenue allocations reached for this class in the March 14 Settlement and ensure that they are fully recovered through SLP rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the March 14 Settlement, and reflects a reasonable compromise of Settling Parties' proposals.

The SLP Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Tables 1 and 2 of the March 14 Settlement, which were based on the January 1, 2011 effective rates and revenue requirements. The SLP Settling Parties agree that the actual rates derived at the time of implementation of this SLP Settlement, once adopted by the CPUC, shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the SLP class. Adopted revenue requirements in effect at the time of settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates that will result when the Phase 2 rate changes are implemented will vary from those shown in

Exhibit A. However, these actual rates shall be based on the rate design methods described in this SLP Settlement Agreement.

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

The SLP Settling Parties further agree that this SLP Settlement resolves all SLP rate design issues in A.10-03-014.

B. SLP Settlement Rates

1. Illustrative Settlement Rates

The SLP Settling Parties agree that rates to collect the revenue allocated to the SLP customer classes under the March 14 Settlement shall be designed consistent with the illustrative rates set forth below and in Exhibit A, for Schedules A-1, A-1-TOU, A-6, A-15, TC-1 and E-CARE.

The SLP Settling parties further agree that the same methods used to determine the illustrative rates provided herein will be applied to the revenue requirement in effect when this Settlement is implemented, as described in Section A above.

2. Methods Used To Develop Illustrative Settlement Rates

The SLP Settling Parties agree that the basic rate designs for each of the applicable SLP rate schedules will be updated upon implementation of this settlement using the methods underlying development of the illustrative settlement rates for Schedules A-1, A-1-TOU, A-6, A-15, TC-1 and E-CARE set forth in this supplemental SLP Settlement Agreement.

The SLP Settling Parties agree that customer charges for Schedules A-1, A-1-TOU, and A-6, will be set at $10 per month for single-phase service and $20 per month for poly-phase service. The SLP Settling Parties further agree that Schedules A-15 and TC-1 will use the $10 per month single-phase customer charge.

The SLP Settling Parties agree that Schedules A-1, A-1-TOU, A-6, and A-15 shall be designed on a revenue-neutral basis, with Schedule A-15 paying a $25 per month special facility charge in addition for direct current service. Schedule TC-1 is designed separately, based upon its own revenue allocation, not upon a revenue neutral approach.

The distribution component energy charge principles are based upon PG&E's January 7, 2011 filed proposals and are updated to reflect the March 14 Settlement regarding generation component energy charges. The updates generally reflect PG&E's January 7, 2011 filed proposals, but with the exception that Schedule A-6 rates have been modified through settlement to reshape generation energy charges to provide slightly greater time-of-use (TOU) differentiation than proposed by PG&E.

The above methods shall be used to set initial rates upon implementation of this settlement at then-current revenue requirements using settlement revenue allocation principles. All subsequent rate changes until a decision in the next GRC Phase 2 proceeding shall be governed by the principles set forth in the March 14 revenue allocation settlement in Section VIII, 3a and 3f, for Rate Changes Between GRCs. However, this is generally superseded herein by this SLP agreement to instead assure that all subsequent rate changes maintain the aforementioned revenue neutrality between Schedules A-1, A-1-TOU, A-6, and A-15, to prevent rates by schedule from drifting apart and establishing inappropriate rate relationships between rate schedules.

3. Schedule A-6 Rate Design

The SLP Settling Parties incorporate by reference herein the terms set forth in the MLLP Settlement Agreement related to the "Schedule A-6 Solar Pilot."

The SLP Settling Parties agree to a compromise that allocates 50 percent rather than 100 percent of PG&E's proposed non-marginal distribution costs to the flat adder, resulting in TOU differentiation below DRA's initial proposal, above that proposed by PG&E, and close to that proposed by Solar Alliance.

In addition, the SLP Settling Parties agree to slightly modify off-peak rates in each season by altering the seasonal distribution allocation to better meet the original objectives of both DRA and Solar Alliance to set the summer-off peak rate approximately 1.0 cents per kWh above the winter off-peak rate, as shown in Exhibit A's illustrative rates.

4. Kilowatt Threshold Delineating Small from Medium L&P

The SLP Settling Parties agree to delineate the threshold between the Small L&P and Medium L&P customer classes as follows:

a. First Wave of Threshold Phase-In

Require L&P customers over 75 kW to migrate off Small L&P Schedules A-1, A1-TOU and A1-PDP only after the customer has 12 months of interval data. This is expected to move approximately 3,000 Schedule A-1, A1-TOU and A1-PDP customers over 75 kW to Schedule A-6, A6-PDP, A10-TOU, A10-PDP, E-19V or E-19V-PDP. Non-TOU A-10 may also be available if the customer is not yet subject to default to TOU as ordered by Decision 10-02-032. The transition date for the First Wave would be the later of: (a) November 1, 2012 or (b) the date customers have 12 months of interval data available, provided however, that if the Commission mandates mandatory TOU for these customers beginning November 1, 2012, each customer's transition under the 75 kW threshold articulated here would occur on the same day as the transition to mandatory TOU. In the event that kW data is not available, 150,000 kWh per year shall be used as a proxy for the 75 kW threshold.

b. Second Wave of Threshold Phase-In

Further reductions in the kW cutoff threshold may be reconsidered in PG&E's 2014 GRC Phase 2 proceeding. To facilitate such consideration, DRA agrees to provide PG&E with a lower kW cutoff threshold approximately 9 months in advance of the filing date of PG&E's 2014 GRC Phase 2 application. At that time, DRA and PG&E will confer and attempt to reach an agreement on a lower cutoff kW threshold. If no agreement is reached, PG&E then agrees to make a good faith effort to analyze the DRA and PG&E kW cutoff thresholds in parallel so that items 3a and 3b below would be of comparable accuracy under the alternate kW cutoff thresholds. PG&E agrees to provide the following information to DRA, within 60 days after PG&E files its 2014 GRC Phase 2 application:

i. An alternate revenue allocation, reflecting a lower maximum kW threshold or kWh proxy for A-1, A1-TOU, and A1-PDP eligibility, as may be proposed by DRA in the 2014 GRC Phase 2, and assuming the customers migrating from A-1 will move to A10-TOU; and

ii. Billing determinants needed to compute correct rates for A-1, A10-TOU, and related classes affected by a proposal (if any) by DRA to lower the maximum kW eligible for A-1, A1-TOU and A1-PDP service.

5. Schedule A-15 DC Meter Issue

The SLP Settling Parties agree that it is reasonable for customers on Schedule A-15 whose direct current (DC) meter, in PG&E's opinion, is not functioning properly and for which no utility grade replacement meter is available, to have their DC usages estimated for the purposes of billing under that rate schedule. A customer's usage may be estimated by (a) providing that customer with a replacement non-revenue-quality DC meter, or (b) installing a temporary metering device to establish an average fixed monthly usage, or (c) calculating an average fixed monthly usage based on motor sizes, equipment capacity ratings, end-uses, load factor or usage patterns, site inspections or surveys, and records of historical usage. No back-billing for undercharges for non-registering meters would occur.

The Schedule A-15 billing for customers with DC meters that are not functioning correctly will be under a special agreement under Schedule A-15. After a final decision in this proceeding, PG&E shall file a compliance advice letter that will include a customer agreement form specific to Schedule A-15 to address the issue of DC meters that are not functioning properly. This customer agreement form will be similar in format and content to Form 79-972, *Agreement for Unmetered Electrical Service*, modified as appropriate.

6. Schedule E-CARE

The SLP Settling Parties agree that it is reasonable to adopt the Schedule E-CARE rate design for Commercial CARE customers set forth in Exhibit A. This sets appropriate per-kWh rate discounts by rate schedule to establish parity with the level of average CARE rate discounts in the residential sector, as updated to reflect the new CARE Tier 3 rate, $2.40 per month CARE customer charge, and baseline quantity changes, if adopted by the Commission. Should the residential rate design measures and associated CARE discounts adopted by the Commission differ from those assumed here, the Commercial CARE rate per kWh discounts will be revised to achieve any parity with the adopted average residential CARE rate discount. These discounts will also, on that same basis, commensurately change with each future electric rate change.

7. No Annual Billing

The SLP Settling Parties agree that it is reasonable not to adopt the City of Hercules proposal for annual billing rather than monthly billing for low-usage customers. The Settling Parties believe that the SLP Settlement's lower single-phase customer charge, consolidated billing, and online e-bills, available upon request, reasonably address the concerns raised by the City of Hercules.

8. Peak Day Pricing Rate Refinements

The SLP Settling Parties agree that it is reasonable to adopt the refinements to Schedule A-1-TOU and Schedule A-6 Peak Day Pricing (PDP) rates proposed by PG&E in Chapter 9 of Exhibit (PG&E-14).

9. Schedule TC-1

The SLP Settling Parties agree that it is reasonable to adopt an intra-class revenue allocation that reflects the fact that TC-1 customers have very high load factors compared to all other small L&P customers.

10. Discounted Price Floors for Schedules ED and E-31

The SLP Settling Parties incorporate by reference herein the terms set forth in the MLLP Settlement Agreement related to "Discounted Price Floors for Schedules ED and E-31." Schedule ED does not encompass the SLP class, because Schedule ED is applicable only to customers with maximum demands greater than 200 kW, however, Schedule E-31 encompasses the SLP class because it is applicable to customers with maximum demands greater than 20 kW.

11. Other

Unless otherwise specifically agreed by the parties or addressed in this SLP Settlement Agreement above, the proposals, methods and explanations contained in Chapter 4 of Exhibit PG&E 14, served on January 7, 2011, shall be adopted for the purpose of implementing rates under this Settlement. Unless default TOU and default PDP D.10-02-032 is modified by Commission action on one or more Petitions to Modify pending at the time this SLP settlement agreement was executed, the Settling Parties understand that the non-TOU A-1 rate is being retained only on an interim basis for those customers without 12 months of interval billing data, and once the trigger for these customers to default to TOU is reached customers must take service on a TOU or PDP rate.

VI. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the March 14 Settlement, Term VIII, Subsections 2 and 3, shall apply to this SLP Settlement, unless specifically noted above.

Certain elements of this SLP Settlement Agreement will or may require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. Such structural and system changes will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The SLP Settling Parties recognize that such changes could take several months to implement.

VII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This SLP Settlement shall become effective among the SLP 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 SLP Settling Parties hereto have duly executed this SLP Settlement on behalf of the SLP Settling Parties they represent.

Exhibit A

ILLUSTRATIVE SLP SETTLEMENT RATES

SCHEDULES A-1, A-6, A-15, TC-1 and E-CARE

*Total revenues calculated here do not include E-CARE discounts, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
A-1						
ENERGY CHARGES ($/kWh)						
Summer	4,070,765,321	$0.19589	$797,422,219	4,070,765,321	$0.19599	$797,835,281
Winter	3,587,718,440	$0.14574	$522,874,085	3,587,718,440	$0.14270	$511,962,690
Revenue from Energy Charges			$1,320,296,304			$1,309,797,971
Revenue from Energy as % of Total			95.95%			94.72%
CUSTOMER CHARGE ($/meter/mo.)						
Singlephase	2,864,721	$9.00	$25,782,485	2,864,721	$10.00	$28,647,206
Polyphase	2,214,872	$13.50	$29,900,766	2,214,872	$20.00	$44,297,431
Revenue from Customer Charges			$55,683,252			$72,944,637
Revenue from Customer as % of Total			4.05%			5.28%
TOTAL REVENUE			$1,375,979,556			$1,382,742,608
						0.5%

*Total revenues do not include E-CARE discounts or other standby revenue.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
A-1 TOU						
ENERGY CHARGES ($/kWh)						
Summer						
Peak	1,092,008,022	$0.22108	$241,421,133	1,092,008,022	$0.21029	$229,642,956
Part-Peak	1,013,271,802	$0.19521	$197,800,789	1,013,271,802	$0.20378	$206,486,111
Off-Peak	1,965,485,497	$0.17978	$353,354,983	1,965,485,497	$0.18403	$361,706,214
Winter						
Part-Peak	1,745,393,797	$0.15111	$263,746,457	1,745,393,797	$0.15029	$262,312,099
Off-Peak	1,842,324,643	$0.14006	$258,035,989	1,842,324,643	$0.13551	$249,650,591
Revenue from Energy Charges			$1,314,359,351			$1,309,797,971
CUSTOMER CHARGE ($/meter/mo.)						
Singlephase	2,864,721	$9.00	$25,782,485	2,864,721	$10.00	$28,647,206
Polyphase	2,214,872	$13.50	$29,900,766	2,214,872	$20.00	$44,297,431
Revenue from Customer Charges			$55,683,252			$72,944,637
TOTAL REVENUE			$1,370,042,602			$1,382,742,608

Note: current rates were adopted in 2009 RDW and and are not strictly revenue-neutral if applied to the 2011 GRC rate design billing determinants.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
A-6						
ENERGY CHARGES ($/kWh)						
Summer						
Peak	162,509,200	$0.44815	$72,828,498	162,509,200	$0.40055	$65,092,891
Part-Peak	214,285,137	$0.20063	$42,992,027	214,285,137	$0.21130	$45,278,649
Off-Peak	537,921,834	$0.11987	$64,480,690	537,921,834	$0.13527	$72,765,655
Winter						
Part-Peak	339,984,650	$0.16646	$56,593,845	339,984,650	$0.14899	$50,653,618
Off-Peak	494,752,628	$0.12313	$60,918,891	494,752,628	$0.12445	$61,570,119
Revenue from Energy Charges			$297,813,951			$295,360,932
Revenue from Energy as % of Total			98.81%			98.38%
CUSTOMER CHARGE ($/meter/mo.)						
Singlephase	135,240	$9.00	$1,217,162	135,240	$10.00	$1,352,402
Polyphase	174,838	$13.50	$2,360,312	174,838	$20.00	$3,496,759
Revenue from Customer Charges			$3,577,474			$4,849,161
Revenue from Customer as % of Total			1.19%			1.62%
TOTAL REVENUE			$301,391,425			$300,210,093
						-0.4%

*Total revenues do not include E-CARE discounts, other standby revenue or voluntary TOU meter charges.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

A-15	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
ENERGY CHARGES ($/kWh)						
Summer	302,338	$0.19589	$59,225	302,338	$0.19599	$59,256
Winter	302,247	$0.14574	$44,049	302,247	$0.14270	$43,130
Revenue from Energy Charges			$103,274			$102,386
Revenue from Energy as % of Total			37.06%			32.60%
CUSTOMER CHARGE ($/meter/mo.)	6,049	$9.00	$54,437	6,049	$10.00	$60,486
Revenue from Customer Charges			$54,437			$60,486
Revenue from Customer as % of Total			19.53%			19.26%
FACILITIES CHARGE ($/meter/mo.)	6,049	$20.00	$120,971	6,049	$25.00	$151,214
Revenue from Facilities Charge			$120,971			$151,214
Revenue from Facilities as % of Total			43.41%			48.14%
TOTAL REVENUE			$278,683			$314,085
						12.7%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
TC-1						
ENERGY CHARGES ($/kWh)						
Summer	18,134,107	$0.13	$2,439,763	18,134,107	$0.13679	$2,480,497
Winter	18,277,316	$0.13	$2,459,030	18,277,316	$0.13679	$2,500,086
Revenue from Energy Charges			$4,898,793			$4,980,583
Revenue from Energy as % of Total			79.68%			78.20%
CUSTOMER CHARGE ($/meter/mo.)	138,833	$9.00	$1,249,494	138,833	$10.00	$1,388,326
Revenue from Customer Charges			$1,249,494			$1,388,326
Revenue from Customer as % of Total			20.32%			21.80%
TOTAL REVENUE			$6,148,287			$6,368,909
						3.6%

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES			ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
E-CARE						
A-1		($0.08350)			($0.07469)	
A-6		($0.08083)			($0.07130)	
A-15		($0.08350)			($0.07469)	
A-10		($0.07459)			($0.06578)	
E-19		($0.06575)			($0.05782)	
E-20		($0.05654)			($0.04937)	

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

	Dist	Gen	PPP	Other	Total
A-1					
ENERGY CHARGES ($/kWh)					
Summer	$0.06627	$0.08359	$0.01683	$0.02930	$0.19599
Winter	$0.04105	$0.05553	$0.01683	$0.02930	$0.14270
CUSTOMER CHARGE ($/meter/mo.)					
Singlephase	$10.00				$10.00
Polyphase	$20.00				$20.00
A-1 TOU					
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.06627	$0.09790	$0.01683	$0.02930	$0.21029
Part-Peak	$0.06627	$0.09138	$0.01683	$0.02930	$0.20378
Off-Peak	$0.06627	$0.07163	$0.01683	$0.02930	$0.18403
Winter					
Part-Peak	$0.04105	$0.06312	$0.01683	$0.02930	$0.15029
Off-Peak	$0.04105	$0.04834	$0.01683	$0.02930	$0.13551
CUSTOMER CHARGE ($/meter/mo.)					
Singlephase	$10.00				$10.00
Polyphase	$20.00				$20.00

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

	Dist	Gen	PPP	Other	Total
A-6					
ENERGY CHARGES ($/kWh)					
Summer					
Peak	$0.16490	$0.19120	$0.01515	$0.02930	$0.40055
Part-Peak	$0.07717	$0.08968	$0.01515	$0.02930	$0.21130
Off-Peak	$0.04280	$0.04802	$0.01515	$0.02930	$0.13527
Winter					
Part-Peak	$0.03371	$0.07083	$0.01515	$0.02930	$0.14899
Off-Peak	$0.03430	$0.04570	$0.01515	$0.02930	$0.12445
CUSTOMER CHARGE ($/meter/mo.)					
Singlephase	$10.00				$10.00
Polyphase	$20.00				$20.00
A-15					
ENERGY CHARGES ($/kWh)					
Summer	$0.06627	$0.08359	$0.01683	$0.02930	$0.19599
Winter	$0.04105	$0.05553	$0.01683	$0.02930	$0.14270
CUSTOMER CHARGE ($/meter/mo.	$10.00				$10.00
FACILITIES CHARGE ($/meter/mo.)	$25.00				$25.00

PACIFIC GAS AND ELECTRIC COMPANY
2011 GRC Rate Design Changes - Exhibit A

ILLUSTRATIVE RATES FOR RATE DESIGN SETTLEMENT

TC-1	Dist	Gen	PPP	Other	Total
ENERGY CHARGES ($/kWh)					
Summer	$0.04347	$0.05658	$0.00744	$0.02930	$0.13679
Winter	$0.04347	$0.05658	$0.00744	$0.02930	$0.13679
CUSTOMER CHARGE ($/meter/mo.	$10.00				$10.00
E-CARE					
A-1	($0.06269)		($0.00695)	($0.00505)	($0.07469)
A-6	($0.05930)		($0.00695)	($0.00505)	($0.07130)
A-15	($0.06269)		($0.00695)	($0.00505)	($0.07469)
A-10	($0.05378)		($0.00695)	($0.00505)	($0.06578)
E-19	($0.04582)		($0.00695)	($0.00505)	($0.05782)
E-20	($0.03737)		($0.00695)	($0.00505)	($0.04937)

(END OF APPENDIX C)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON STREETLIGHT RATE DESIGN ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Streetlight Rate Design Settlement Agreement (STL Settling Parties) agree on a mutually acceptable outcome to the rate design issues for the streetlight class[1] in Application (A.) 10-03-014, Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.[2]

Although the active parties held differing views on numerous aspects of streetlight rate design, they bargained earnestly and in good faith to seek a compromise and to develop this Settlement, which is the product of arms-length negotiations. These negotiations considered the interests of all active parties on streetlight rate design issues, and the Settlement addresses each of these issues in a fair and balanced manner.

The STL Settling Parties crafted this Settlement by agreeing to concessions and trade-offs among themselves. Thus the various elements and sections of this Settlement are intimately interrelated, and should not be altered as the Settling Parties intend that the Settlement be treated as a package solution which strives to balance and align the interests of each party. Accordingly, the STL Settling Parties respectfully request that the Commission approve each and every aspect

1 The Streetlight (STL) customer class encompasses and is defined as: Schedules LS-1, LS-2, LS-3 and OL-1, and CCSF Streetlight rates as described in PG&E's January 7, 2011 update Exhibit PGE-14 Chapter 8.

of the Settlement without modification. Any material change to this Settlement shall render it null and void, unless all of the STL Settling Parties agree in writing to such changes.

This Streetlight Settlement is supplemental to the Settlement in A. 10-03-014 filed with the CPUC on March 14, 2011 (March 14 Settlement), in that it uses the revenue allocation agreed to in the March 14 Settlement and addresses Streetlight issues that were not resolved in the March 14 Settlement. The Streetlight Settlement's outcomes are complementary with those of the March 14 Settlement. Ordinarily, the entirety of this settlement would be consolidated in the Commission's final decision in this proceeding. However, there is time sensitivity for implementing the new network controlled dimmable streetlight pilot program, specifically in or about August 2011 if possible, so as to allow the very earliest adopter city(ies) to realize savings from reduced usage as soon as they begin such installations. Therefore, the STL Settling Parties agree that the network controlled streetlight pilot program portion (set forth in Section V. C of this Settlement) should proceed on an expedited basis. To that end, they have agreed that PG&E will submit an Advice Letter seeking a variance from LS-2 to allow the pilot to go forward upon approval of the Advice Letter, without having to wait for a final decision on all GRC Phase 2 issues.

The details of this Streetlight Settlement are set forth herein.

II. STREETLIGHT SETTLING PARTIES

The STL Settling Parties are as follows:

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

CAL-SLA represents cities and counties throughout California, including in PG&E's service territory. Specifically, CAL-SLA's membership includes the Cities of San Jose and Oakland, who each submitted testimony in Phase 2 seeking a network controlled streetlight rate. The Cities of San Jose and Oakland participated in and were directly involved in settlement discussions in addition to staff for CAL-SLA itself. In signing this Settlement, CAL-SLA is representing the interests of these cities.

III. STREETLIGHT SETTLEMENT CONDITIONS

This Streetlight Settlement resolves the issues raised by the STL Settling Parties in A.10-03-014 on streetlight rate design, subject to the conditions set forth below:

1. This STL Settlement embodies the entire understanding and agreement of the STL Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the STL Settling Parties with respect to those matters. This STL Settlement builds on the underlying marginal cost and revenue allocation in the March 14 Settlement and incorporates that agreement by reference.
2. This STL Settlement represents a negotiated compromise among the STL Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of this Settlement only to arrive at the agreement embodied herein. Nothing contained in this STL Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the STL Settling Parties on these matters in this proceeding. This STL Settlement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.

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

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

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

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

7. The STL Settling Parties intend that the terms of the STL Settlement are to be interpreted and treated as a unified, integrated agreement incorporating the March 14 Settlement, which forms the foundation for the STL rate design agreed to herein. In the event the Commission rejects or modifies any portion of this STL Settlement or the underlying March 14 Settlement, the STL Settling Parties reserve their rights under CPUC Rule 12.4.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The overall procedural and settlement history of A.10-03-14 is set forth in Section IV of the March 14, 2011 Settlement on marginal cost and revenue allocation issues in this proceeding, to which this STL Settlement is supplemental, and which is incorporated herein by reference.

V. STL SETTLEMENT TERMS

A. General Terms

The STL Settling Parties agree that the primary purpose of rate design for the STL customer classes is to take the revenue allocations reached for those classes in the March 14 Settlement and ensure that they are fully recovered through STL rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the March 14 Settlement, and reflects a reasonable compromise of STL Settling Parties' proposals.

The STL Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Tables 1 and 2 of the March 14 Settlement, which was based on January 1, 2011 effective rates and revenue requirements. The STL Settling Parties agree that the actual rates derived at the time of implementation of this STL Settlement, once adopted by the CPUC, shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the STL classes. Adopted revenue requirements in effect at the time of settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates that will result when the Phase 2 rate changes are implemented will vary from those shown in Attachment 2. However, these actual rates shall be based on the rate design methods described in this STL Settlement Agreement.

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

The STL Settling Parties further agree that this STL Settlement resolves all STL rate design issues in A.10-03-014.

B. STL Settlement Rates

1. Illustrative Settlement Rates

The STL Settling Parties agree that rates to collect the revenue allocated to the STL customer class under the March 14 Settlement shall be designed consistent with the illustrative rates set forth below and in Attachments 1 and 2 to this agreement.

As detailed below, the STL Settling Parties agree that it is reasonable to adopt the facility charge rates for Schedules LS-1, LS-2, OL-1 and CCSF that are presented in Attachment 1. The agreed total rates for each lamp type for Schedules LS-1, LS-2, and OL-1 are presented in Attachment 2 and are based on the revenue allocation settlement presented in the Settlement Agreement on Marginal Cost and Revenue Allocation dated March 14, 2011.

2. Methods Used To Develop Illustrative Settlement Rates

The STL Settling Parties agree that the basic rate designs on the energy charge portion of the rate for each of the applicable STL rate schedules will be updated upon implementation of this STL Settlement using the methods underlying development of the illustrative settlement rates for Schedules LS-1, LS-2, LS-3 and OL-1 set forth in this supplemental settlement agreement.

The above methods shall be used to set initial energy charge portion of the street light rates upon implementation of this STL Settlement at the then-current revenue requirements using settlement revenue allocation principles. The facility charge portion of the rate as shown in Attachment 1 will remain unchanged until they are revised in PG&E's next GRC Phase 2 proceeding.

All subsequent rate changes on the energy charge portion of the street light rates, until PG&E's next GRC Phase 2 decision, shall be governed by the principles set forth, in the March

14, 2011 Revenue Allocation Settlement Agreement, in Section VIII, 3a and 3f, for Rate Changes Between General Rate Cases.

C. Pilot Program for Network Controlled Dimmable Streetlights

The STL Settling Parties agree that the new Pilot Program for Network Controlled Dimmable Streetlights, which is set forth in detail in Attachment 3 to this Settlement, is reasonable and should be adopted.

Ordinarily, the entirety of this Settlement would be consolidated with all the other Supplemental Settlements on rate design in the Commission's final rate design decision in the GRC Phase 2 proceeding. However, time sensitivity for potential participants in the pilot program argues for more prompt implementation of the new network controlled dimmable streetlight pilot program so that participants may more promptly realize savings due to expected reduced energy usage using network control technologies as soon as they begin to be installed, which may be as soon as August 2011. For this reason, this STL Settlement Agreement provides that, upon execution, by the STL Settling Parties, PG&E will promptly file an Advice Letter seeking CPUC authorization for a variance to the current LS-2 schedule to create a pilot program, establishing a "Special Contract for Unmetered Service." Thus, the proposal to establish a network controlled dimmable streetlight pilot program will become effective upon approval of the Advice Letter, which may be issued before a final decision on all GRC Phase 2 issues.

D. Future Workshops on Streetlight Marginal Costs and Rate Design Model

As part of the marginal customer cost analysis PG&E conducts for streetlighting in preparation for filing PG&E's 2014 GRC Phase 2 application, PG&E will identify which costs are marginal and which costs are facilities for purposes of streetlight rate design in order to ensure that these costs are not double counted.

PG&E will also develop a simplified streetlight rate design model and share that model with CAL-SLA for its review and input at the workshop that will address revenue allocation issues prior to the next GRC Phase 2, pursuant to the March 14, 2011 Settlement Agreement.

E. Other

Unless otherwise specifically agreed by the parties or addressed in this STL Settlement Agreement above and in the attachments hereto, the proposals, methods and explanations contained in revenue allocation and rate design Exhibit PG&E-14. Chapter 8, served on January 7, 2011, shall be adopted for the purpose of implementing rates under this Settlement.

V. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the March 14 Settlement, Term VIII. Subsections 2 and 3, shall apply to this STL Settlement Agreement, unless specifically noted above.

Certain elements of this STL Settlement Agreement will require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. These structural and system changes will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The STL Settling Parties recognize that these changes could take several months to implement.

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

The undersigned represent that they are authorized to sign on behalf of the Party Represented, for purposes of this STL Settlement in Phase 2 of PG&E's 2011 GRC:

California City-County Street Light Association

By: ______/s/______________________
DAVID J. BYERS

Title: __Attorney for CAL-SLA_

Date: 06/03/11

Pacific Gas and Electric Company

By: __________/s/________________
AMRIT SINGH

Title: Senior Director, Analysis and Rates__

Date: 06/03/11

ATTACHMENT 1

ILLUSTRATIVE STL SETTLEMENT FACILITY CHARGE RATES FOR SCHEDULES LS-1, LS-2, OL-1 and CCSF

	A	B	C	D	E	F	G	H	I	J	K
1											
2	2011 GRC SIMPLIFIED STREETLIGHT MODEL										
3	Facility Charges (Settlement) for LS-1, LS-2, OL-1 and City and County of San Francisco										
4		Rate Schedule	Service	2011 Lamp Count for Plant Charge	2011 Lamp Count for Universal Charge	2011 Lamp Count for O&M Charge	Plant Charge per Month	Universal Charge (Settlement Proposal)	O&M Charge (Settlement Proposal)	Total Monthly Facility Charge	Annual Revenues - Full Cost ($000)
5	1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights	84,972	84,972	84,972	$3.988	$0.2060	$2.176	$6.370	$ 6,496
6	2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities	45	45	45	$2.190	$0.206	$2.176	$4.572	$ 2
7	3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required (ownership of pole or post, support arm and foundation by customer).	19,988	19,988	19,988	$2.261	$0.206	$2.176	$4.643	$ 1,114
8	4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation	15,687	15,687	15,687	$4.861	$0.206	$2.176	$7.243	$ 1,364
9	5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation.	36,820	36,820	36,820	$4.473	$0.206	$2.176	$6.855	$ 3,029
10	6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its wood pole or post, installed solely for the luminaire.	27,852	27,852	27,852	$5.527	$0.206	$2.176	$7.909	$ 2,643
11	7	LS-2A	City Owned and Maintained		536,017		$0.000	$0.206		$0.206	$ 1,325
12	8	LS-2B	City Owned and PG&E Maintained		0	0	$0.000	$0.206	$2.176	$2.382	$ -
13	9	LS-2C	City Owned and PG&E Maintained		25,724	25,724	$0.000	$0.206	$2.176	$2.382	$ 735
14	10	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property.	21,660	21,660	21,660	$3.988	$0.206	$2.176	$6.370	$ 1,656
15		CCSF Standard:									
16	11		CCSF Rate Schedule No. 1 (LS-1A HPSV 100W)	16,749	16,749	16,749	$4.048	$0.206	$2.176	$6.430	$ 1,292
17	12		CCSF Rate Schedule No. 3 (LS-1A HPSV 150W)	198	198	198	$4.054	$0.206	$2.176	$6.436	$ 15
18	13		CCSF Rate Schedule No. 4E (LS-1E HPSV 100W)	1,009	1,009	1,009	$4.564	$0.206	$2.176	$6.946	$ 84
19	14		CCSF Rate Schedule No. 4A (LS-1E Mercury Vapor 175W)	8	8	8	$6.181	$0.206	$2.176	$8.563	$ 1
20	15		CCSF Rate Schedule No. 6 (LS-2B)		24	24	$0.000	$0.206	$2.176	$2.382	$ 1
21	16		CCSF Rate Schedule No. 7								
22		CCSF Non-Standard									
23			CCSF Rate Schedule No. 4A								
24	17		Incandescent 295W	894	894	894	$5.701	$0.206	$2.176	$8.083	$ 87
25	18		Mercury Vapor 400W	2	2	2	$5.978	$0.206	$2.176	$8.360	$ 0
26			CCSF Rate Schedule No. 5								
27	19		HPSV 100W	54	54	54	$6.000	$0.206	$2.176	$8.381	$ 5
28	20		Incandescent 405W	132	132	132	$7.096	$0.206	$2.176	$9.478	$ 15
29			CCSF Rate Schedule No. 6A (Chinatown Area) - HSPV 250W	59	59	59	$72.534	$0.206	$2.176	$74.916	$ 53
30			CCSF Rate Schedule No. 9 (Triangle District)								
31			HPSV:								
32	21		150W 16,000 LUMENS DUPLEX (1)	193	193	193	$26.718	$0.206	$2.176	$29.100	$ 67
33	22		150W 16,000 LUMENS DUPLEX (2)	193	193	193	$0.949	$0.206	$2.176	$3.331	$ 8
34	23	CCSF Subtotal		19,491	19,515	19,515	$4.579	$0.206	$2.176	$6.961	$ 1,629
35	24	Subtotal		226,515	788,280	252,263					$ 19,992
36	25	SP-2A1			21			$0.206		$0.206	$ 0
37											
38	26	Lamp Count		226,515	788,301	252,263					
39	27	Annual Revenues ($000)		$11,456	$1,949	$6,587					$ 19,992

ATTACHMENT 2

Illustrative Total Rates for Each Streetlight Lamp Type

For Schedules LS-1, LS-2, OL-1

PACIFIC GAS AND ELECTRIC COMPANY

TOTAL RATES (2011 GRC PHASE 2 SETTLEMENT) FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS											
LAMP WATTS	AVERAGE kWhr PER MONTH	LUMENS	LS-2A	LS-2C	LS-1A	LS-1B	LS-1C	LS-1D	LS-1E	LS-1F	OL-3
MERCURY VAPOR LAMPS											
40	18	1,300	$2.386	--	--	--	--	--	--	--	--
50	22	1,650	$2.870	--	--	--	--	--	--	--	--
100	40	3,500	$5.050	$7.226	$11.214	--	$9.487	--	--	--	--
175	68	7,500	$8.441	$10.617	$14.605	$12.807	$12.878	--	$15.090	$16.144	$15.078
250	97	11,000	$11.954	$14.130	$18.118	$16.320	$16.391	--	--	--	--
400	152	21,000	$18.615	$20.791	$24.779	$22.981	$23.052	--	--	--	$25.836
700	266	37,000	$32.421	$34.597	$38.585	$36.787	$36.858	--	--	--	--
1,000	377	57,000	$45.864	$48.040	--	--	--	--	--	--	--
INCANDESCENT LAMPS											
58	20	600	$2.628	--	$8.792	--	--	--	--	--	--
92	31	1,000	$3.960	$6.136	$10.124	--	--	--	--	--	--
189	65	2,500	$8.078	$10.254	$14.242	$12.444	--	--	--	--	--
295	101	4,000	$12.438	$14.614	$18.602	$16.804	--	--	--	--	--
405	139	6,000	$17.040	$19.216	$23.204	--	--	--	--	--	--
620	212	10,000	$25.881	$28.057	--	--	--	--	--	--	--
860	294	15,000	$35.812	--	--	--	--	--	--	--	--
LOW PRESSURE SODIUM VAPOR LAMPS											
35	21	4,800	$2.749			--	--	--	--	--	--
55	29	8,000	$3.718			--	--	--	--	--	--
90	45	13,500	$5.656			--	--	--	--	--	--
135	62	21,500	$7.715			--	--	--	--	--	--
180	78	33,000	$9.653			--	--	--	--	--	--

PACIFIC GAS AND ELECTRIC COMPANY

TOTAL RATES (2011 GRC PHASE 2 SETTLEMENT) FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS LAMP WATTS	AVERAGE kWhr PER MONTH	LUMENS	LS-2A	LS-2C	LS-1A	LS-1B	LS-1C	LS-1D	LS-1E	LS-1F	OL-3
HIGH PRESSURE SODIUM VAPOR LAMPS AT 120 VOLTS											
35	15	2,150	$2.023	--	--	--	--	--	--	--	--
50	21	3,800	$2.749	--	--	--	--	--	--	--	--
70	29	5,800	$3.718	$5.894	$9.882	--	$8.155	$10.755	$10.367	$11.421	$10.084
100	41	9,500	$5.171	$7.347	$11.335	--	$9.608	$12.208	$11.820	$12.874	$11.621
150	60	16,000	$7.473	$9.649	$13.637	--	$11.910	$14.510	$14.122	$15.176	--
200	80	22,000	$9.895	--	$16.059	--	$14.332	$16.932	$16.544	$17.598	--
250	100	26,000	$12.317		$18.481	--	$16.754	$19.354	$18.966	$20.020	
400	154	46,000	$18.857		$25.021	--	$23.294	$25.894	$25.506	$26.560	
AT 240 VOLTS											
50	24	3,800	$3.113	--	--	--	--	--	--	--	--
70	34	5,800	$4.324	$6.500	$10.488	--	--	--	--	--	--
100	47	9,500	$5.898	$8.074	$12.062	--	$10.335	--	$12.547	$13.601	--
150	69	16,000	$8.563	$10.739	$14.727	--	$13.000	--	$15.212	$16.266	--
200	81	22,000	$10.016	$12.192	$16.180	--	$14.453	--	$16.665	$17.719	$16.743
250	100	25,500	$12.317	$14.493	$18.481	--	$16.754	--	$18.966	$20.020	$19.176
310	119	37,000	$14.618	--	--	--	--	--	--	--	--
360	144	45,000	$17.646	--	--	--	--	--	--	--	--
400	154	46,000	$18.857	$21.033	$25.021	--	$23.294	--	$25.506	$26.560	$26.092
METAL HALIDE LAMPS											
70	30	5,500	$3.839	--	--	--	--	--	--	--	--
100	41	8,500	$5.171	--	--	--	--	--	--	--	--
150	63	13,500	$7.836	--	--	--	--	--	--	--	--
175	72	14,000	$8.926	--	--	--	--	--	--	--	--
250	105	20,500	$12.923	--	--	--	--	--	--	--	--
400	162	30,000	$19.826	--	--	--	--	--	--	--	--
1,000	387	90,000	$47.075	--	--	--	--	--	--	--	--
INDUCTION LAMPS											
23	9	1,840	$1.296	--	--	--	--	--	--	--	--
35	13	2,450	$1.780	--	--	--	--	--	--	--	--
40	14	2,200	$1.902	--	--	--	--	--	--	--	--
50	18	3,500	$2.386	--	--	--	--	--	--	--	--
55	19	3,000	$2.507	--	--	--	--	--	--	--	--
65	24	5,525	$3.113	--	--	--	--	--	--	--	--
70	27	6,500	$3.476	--	--	--	--	--	--	--	--
80	28	4,500	$3.597	--	--	--	--	--	--	--	--
85	30	4,800	$3.839	--	--	--	--	--	--	--	--
100	36	8,000	$4.566	--	--	--	--	--	--	--	--
120	42	8,500	$5.233	--	--	--	--	--	--	--	--
135	48	9,450	$6.019	--	--	--	--	--	--	--	--
150	51	10,900	$6.383	--	--	--	--	--	--	--	--
165	58	12,000	$7.230	--	--	--	--	--	--	--	--
200	72	19,000	$8.926	--	--	--	--	--	--	--	--

NOMINAL LAMP RATINGS

LAMP WATTS	AVERAGE kWhr PER MONTH	LUMENS	LS-2A
LIGHT EMITTING DIODE (LED) LAMPS			
0.0-5.0	0.9		$0.315
5.1-10.0	2.6		$0.521
10.1-15.0	4.3		$0.727
15.1-20.0	6.0		$0.933
20.1-25.0	7.7		$1.139
25.1-30.0	9.4		$1.344
30.1-35.0	11.1		$1.550
35.1-.40.0	12.8		$1.756
40.1-45.0	14.5		$1.962
45.1-50.0	16.2		$2.168
50.1-55.0	17.9		$2.374
55.1-60.0	19.6		$2.580
60.1-65.0	21.4		$2.798
65.1-70.0	23.1		$3.004
70.1-75.0	24.8		$3.210
75.1-80.0	26.5		$3.415
80.1-85.0	28.2		$3.621
85.1-90.0	29.9		$3.827
90.1-95.0	31.6		$4.033
95.1-100.0	33.3		$4.239
100.1-105.1	35.0		$4.445
105.1-110.0	36.7		$4.651
110.1-115.0	38.4		$4.857
115.1-120.0	40.1		$5.062
120.1-125.0	41.9		$5.280
125.1-130.0	43.6		$5.486
130.1-135.0	45.3		$5.692
135.1-140.0	47.0		$5.898
140.1-145.0	48.7		$6.104
145.1-150.0	50.4		$6.310
150.1-155.0	52.1		$6.516
155.1-160.0	53.8		$6.722
160.1-165.0	55.5		$6.928
165.1-170.0	57.2		$7.133
170.1-175.0	58.9		$7.339
175.1-180.0	60.6		$7.545
180.1-185.0	62.4		$7.763
185.1-190.0	64.1		$7.969
190.1-195.0	65.8		$8.175
195.1-200.0	67.5		$8.381
200.1-205.0	69.2		$8.587
205.1-210.0	70.9		$8.793
210.1-215.0	72.6		$8.999
215.1-220.0	74.3		$9.204
220.1-225.0	76.0		$9.410

NOMINAL LAMP RATINGS			
LAMP	AVERAGE kWhr PER		
WATTS	MONTH	LUMENS	LS-2A
LIGHT EMITTING DIODE (LED) LAMPS			
225.1-230.0	77.7		$9.616
230.1-235.0	79.4		$9.822
235.1-240.0	81.1		$10.028
240.1-245.0	82.9		$10.246
245.1-250.0	84.6		$10.452
250.1-255.0	86.3		$10.658
255.1-260.0	88.0		$10.864
260.1-265.0	89.7		$11.070
265.1-270.0	91.4		$11.275
270.1-275.0	93.1		$11.481
275.1-280.0	94.8		$11.687
280.1-285.0	96.5		$11.893
285.1-290.0	98.2		$12.099
290.1-295.0	99.9		$12.305
295.1-300.0	101.6		$12.511
300.1-305.0	103.4		$12.729
305.1-310.0	105.1		$12.935
310.1-315.0	106.8		$13.141
315.1-320.0	108.5		$13.346
320.1-325.0	110.2		$13.552
325.1-330.0	111.9		$13.758
330.1-335.0	113.6		$13.964
335.1-340.0	115.3		$14.170
340.1-345.0	117.0		$14.376
345.1-350.0	118.7		$14.582
350.1-355.0	120.4		$14.788
355.1-360.0	122.1		$14.993
360.1-365.0	123.9		$15.211
365.1-370.0	125.6		$15.417
370.1-375.0	127.3		$15.623
375.1-380.0	129.0		$15.829
380.1-385.0	130.7		$16.035
385.1-390.0	132.4		$16.241
390.1-395.0	134.1		$16.447
395.1-400.0	135.8		$16.653

Attachment 3

NETWORK CONTROLLED DIMMABLE STREETLIGHT PILOT PROGRAM

Preamble

The Streetlight Settling Parties' intent is to explore the usage reduction potential of new streetlight control devices to be demonstrated in certain local governmental jurisdictions, and to find a viable means of reflecting, during this rate case cycle, any related energy savings in a timely, mutually workable way that:

1. Starts to capture additional energy savings as soon as possible after dimmable lights are installed
2. Ensures that self-reported usage data is accurate, revenue quality data
3. Ensures that parasitic loss from the equipment is accounted for. Other non-streetlight or parasitic load will continue to be under separate agreements in accordance with LS-2.
4. Minimize pilot costs, including through eligibility limits, standardized data transfer from loggers, and other conditions of service.
5. Works within interim work-schedule constraints on PG&E's IT/Billing System, as well as those of participating cities.
6. Drive systems standardization for these emerging technologies
7. Provides data and experience from early adopters under the pilot that will allow all participants to work to define and evaluate the viability of longer-term approaches to dimmable streetlight rates.

Interim Billing Pilot Option

Upon finalization of a Settlement Agreement by the Settling Parties, PG&E will, as soon as possible, file an Advice Letter seeking CPUC authorization for a variance to the current LS-2 schedule to create a pilot program, establishing a "Special Contract for Unmetered Service" with the following features:

1. Eligibility

A limited number participants (no more than five) may participate in the pilot, subject to the following eligibility requirements:

a. In consideration of their significant efforts and expenditures of resources to develop this pilot, and to move forward with network controlled streetlights, the Cities of San Jose and Oakland will receive the first two reservations to participate, subject to their meeting all of the other eligibility requirements below. The three remaining slots shall be available to all other eligible potential participants as of the date the CPUC approves this pilot program.

b. A jurisdiction may secure a "reservation" for one of five slots for potential participation in the pilot program as follows:

i. During its process of preparing and issuing an RFP, each potential participant, other than San Jose or Oakland, must contact PG&E to confirm whether there are still any of the remaining three of the total of five pilot reservation slots potentially available.

ii. Once that potential participant receives a proposal or proposals in response to its RFP or RFB that would enable it to purchase equipment that would result in installation by December 31, 2012 of network control systems for at least 300 networked streetlights (or the difference between the number of networked streetlights previously installed and 300), that potential participant shall provide written notice to PG&E attaching the response(s) to its RFP or RFB. PG&E shall review the responses to RFP or RFB to evaluate whether they have met the requirements set forth in this section (including project installation timeline and minimum number of networked streetlights), and confirm in writing within 14 calendar days of receipt that that potential participant has qualified to reserve one of the 5 total pilot slots. Reservations will be issued on a first-come-first-served basis. If a potential participant satisfies all of the above requirements, but its notice is received by PG&E after five slots have been reserved by other jurisdictions, it shall be placed on the waiting list in the order received and PG&E shall notify it that it has qualified for the waiting list and inform it of its waiting list number.

iii. Each potential participant who has secured a reservation must, within 90 days of receiving PG&E's notification of reservation, provide PG&E with written notice that it has executed a contract with a vendor to install equipment that would result in at least 300 networked streetlights (or the difference between the number of networked streetlights previously installed and 300) by December 31, 2012, and attach to such notice a copy of that contract. PG&E shall, within 14 calendar days of receipt of such contract, review it and provide notice to the potential participant as to whether it has qualified as a pilot participant.

iv. If the potential participant does **not** fully execute a contract within 90 days of receiving PG&E's notification of its reservation in the pilot program, or if PG&E determines that its contract could not result in installation of equipment that would result in at least 300 networked streetlights (or the difference between the number of networked streetlights previously installed and 300) by December 31, 2012, that potential participant shall lose its reservation and be placed on the end of the pilot waiting list, and PG&E would invite the next potential participant who can meet these requirements to complete the reservation process.

v. Each participant that has received a slot in the pilot must still meet all other eligibility requirements set forth in Section 1. If at any time during the pilot PG&E determines that a participant does not meet all eligibility requirements, PG&E shall provide a notice of ineligibility to that participant specifying each and every requirement it has been found not to meet. If it cannot document that it has cured and now meets each and every such eligibility requirement within 60 days of such notice, it shall be removed from the pilot program.

vi. Once a potential participant has been provided notice that is has qualified for a slot as one of the total of no more than 5 pilot participants, even if that participant later becomes ineligible or opts out of further participation, its slot in the pilot cannot later be filled by any other potential participant from the waiting list.

vii. The enrolled participants in the pilot program as of December 31, 2012 shall be the only participants eligible for the pilot, and there shall be no further admittances to the program from the waiting list.

c. Each participant who has qualified for one of the five pilot slots must have installed equipment that equips at least 300 public streetlights with a working remote control/monitoring system before December 31, 2012; and

d. Each participant's and potential participant's control/monitoring system must include revenue-grade data loggers capable of meeting Rule 17 and Direct Access (DASMMD) standards for operational accuracy; and

e. Each participant and potential participant must inform PG&E in writing how many new lights it plans to include in the pilot as it makes that determination. Participants will provide more specific information on the streetlights as they are installed, including, but not limited to: the model and manufacturer of the light and monitor/control system as well as the energy consumption of the monitor/control device (*See also*, Section 2 below); and

f. All other non-streetlight or parasitic load must be accounted for and billed under separate agreements; and

g. Each control device must record its own usage, or, per agreement, for total device consumption greater than one watt, the participating customer and PG&E may determine the estimated usage of each device and agree to a fixed adjustment in advance; and

h. To be eligible to for participation in the pilot the potential participant must also meet the following initial technology qualifications:

i. Otherwise eligible customers that have not issued an RFP before this agreement was reached, must first, as part of their RFP process:

a) Arrange for each network control system vendor finalist to do a proof of concept demonstration of its network control technology with PG&E, and

b) Produce and provide to PG&E before selection of final vendor:

- A test export of usage data that meets PG&E's data requirement specifications as set forth below. PG&E will consider utilizing industry standard communications protocols, such as EDI or IEC-CIM, after conclusion of the pilot and when a new rate schedule is implemented; and

- Vendor documentation substantiating network control system data logger accuracy within +/- 2 percent, consistent with Rule 17 and the Direct Access Standards (DASMMD); and

- Documentation showing that there will be a vendor/manufacturer warranty or other enforceable contractual provision that ensures the network control system would be judged to have failed and be eligible for replacement if it does not perform to within +/- 2% throughout the pilot period.

c) Otherwise eligible customers that have completed their purchasing process before this settlement agreement was executed shall work with PG&E and shall ensure that the above technical qualification provisions do not pose a barrier to participation in the pilot.

d) The provision of information to PG&E under this initial technology qualification section for the pilot program does not insert PG&E as an evaluator of finalists for the RFP itself, rather if the potential participant, who is still solely responsible for its own RFP process, selects a vendor that does not meet the above technical qualification provisions, it does so at its own risk of non-eligibility for the pilot program.

2. Notification to PG&E of Controls Deployment by Eligible Participating Customers

a. Eligible customers shall have 5 calendar days from the installation date of any network controlled streetlight device(s) in the field to notify PG&E of the installation. Data files supplying this information are to follow a format to be agreed upon between PG&E and the eligible customer. Data files will be emailed to a dedicated PG&E mailbox to be specified by PG&E. (See pilot workflow timeline in Appendix B hereto, and see footnote 4)

b. For purposes of calculating the bill adjustment, installations received by PG&E with dates less than 5 calendar days from the next billing cycle end date, will not be processed and adjusted in the current month's billing cycle, but will be retroactively adjusted from the install date forward in the following bill cycle.

c. Installations provided to PG&E with dates greater than 5 calendar days since install shall received a bill adjustment for the billing cycle in which they are received, and will include retroactively applied adjustments back to the date of installation.

3. Account Setup

All controlled streetlights will be grouped in a single Account and multiple Service Agreements for bill adjustment on an aggregated basis. Individual Service Agreements will be created for different lighting technologies and fixture wattages. The Service Agreements and Account will be assigned to a billing cycle according to Appendix A. For eligible customers selected to participate in the pilot program, the effective date for the assignment of a controlled light to the new Account and Service Agreements will be the later of the date of the control device installation as reported by the customer, or the date the Account is established. With the exception of the first participant in the pilot program (*see* 1.a above), account set-up shall commence within a reasonable time after PG&E has verified that the customer has qualified for participation and determined that the eligible customer will receive a slot in the pilot program. To facilitate process and procedure development, the new Account and associated Service Agreements for the first participant in the pilot program will be established as soon as possible after approval of this settlement proposal, and controlled lights will be assigned to Service Agreements associated with the Account as soon as practicable after PG&E has received notification of controls deployment.

4. Participant Reporting

Within a customer-specific PG&E-specified time schedule relative to the customer's pilot billing schedule (i.e. within three calendar days of the end of each monthly billing cycle hereto), each and every month during the pilot program[3] each participating customer must report to PG&E the information from the data logger showing the daily energy consumed by each participating streetlight fixture operating under the control and monitoring

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[3] *See* Appendix B for pilot workflow timeline showing the various milepost deadlines within each bi-monthly adjustment cycle, including participant reporting of usage data every month (not only in the even numbered "adjustment months" but also in the odd-numbered non adjustment months)

system (both by streetlight as well as aggregated), **and other data meeting the requirements/format specified in Appendix A hereto**:

a. Customer reports energy consumed by each control device, adjustment made when control device's energy use exceeds 1.0 Watts

b. Equipment Changes: For lights included in the pilot, the participating customer will report all changes to lighting fixtures (fixtures added or removed, or a change in fixture size or type) within 5 calendar days of installation to the PG&E mailbox to be specified by PG&E for data files (See section 2 above). The participating customer will use the reconciliation spreadsheet provided by PG&E to report all lighting changes. (See Appendix A hereto) If the participant requires that the network controlled data logger be removed from a streetlight, the participant must notify PG&E within 5 calendar days of removal. PG&E will then move this streetlight off the pilot account and back onto regular service under Schedule LS-2.

5. PG&E Monthly Validation

Upon receipt of the participating customer's monthly data, PG&E will promptly perform a set of validations on the submitted data to ensure completeness and accuracy, and, if deemed usable, will utilize that data to create a credit/adjustment to the standard LS-2 tariff charges to be included in the customer's bill on a bi-monthly basis (as set forth in Section 6 below).

a. If data is missing, inaccurate, or otherwise found by PG&E to be unusable for this purpose (see Section 8 below), PG&E will promptly communicate that to the submitting customer and request re-submittal, and may take other action as specified below.

b. If the customer has timely submitted daily cumulative usage measurements from its network controlled data loggers, that PG&E has found to be accurate and usable for this purpose, PG&E will calculate the total kilowatt hour usage from the first day of the billing cycle through the last day of the billing cycle by subtraction (*See* Section 6.)

6. Bill

PG&E will provide participating customers with a credit/adjustment, calculated from the validated energy measurements provided by the customer's Streetlight Control and Monitoring system for that month, as an adjustment to the customer's monthly bill under the applicable LS 2 tariff energy charges. Application of the adjustment will be made every other month (bimonthly), with a monthly report to also be provided by PG&E itemizing the basis for adjustment. The adjustment will appear on the bill as a lump sum adjustment to the otherwise applicable LS-2 charges. Participating customers may receive adjustments starting with the date of installation or the date of onset of the pilot whichever date is later.

a. PG&E will sum the validated daily usage values in watt hours or kilowatt hours, submitted by the customer, from the first day of the billing cycle through the last day of the two-month billing adjustment cycle to establish total usage for the period.

b. Using the validated total kilowatt hour values, for each individual streetlight, PG&E will calculate an adjustment equal to the product of the applicable LS-2 energy charge multiplied by the difference between the standard LS-2 usage (all night) and the reported usage (per dimming).

c. The cumulative calculated adjustment for the two prior months will be displayed on the bill every other month at both the individual service agreement level (for the number of lights contained on that service agreement) and at the account level for all lights contained on that account, both of which will be single, aggregated dollar values for the combined number of control equipped lights for which the participating customer has submitted validated data.

d. Participating customers will then pay the amount equal to the overall LS-2 charges after the adjustment reflecting validated controls operation data.

e. In addition to and shortly after PG&E issues the billing statement, PG&E shall also provide participating customers with a bi-monthly electronic report detailing, for each individual streetlight, the validated measured kilowatt hour usage, and the amount of the adjustment calculated, for each separate billing cycle month.

f. For any light with data receipt failure or other data issue that prevents recording or reporting of accurate usage information for a reporting period (per Section 9), the base monthly LS-2 tariff rate will be applied without adjustment. If missing data is subsequently made available within the period specified in Rule 17.1, billing adjustments will be made based on reported data.

g. Where a change in electric rates occurs within a reporting period, daily load information will be used to calculate adjustments based on the effective date of the rate change.

h. The cumulative calculated adjustment will be displayed on the bill every other month at both the individual service agreement level (for the number of lights contained on that service agreement) and at the account level for all lights contained on that account, both of which will be single, aggregated dollar values for the combined number of control equipped lights for which the participant has submitted validated data. The bi-monthly adjustments will be provided to the customer on the bills that nominally end in the following, "even numbered" months:

i.	August
ii	October
iii	December
iv	February
v	April
vi	June

For the other, "odd-numbered" months (July, September, November, January, March and May) the participant will be billed under Schedule LS-2 and shall timely pay its bill without a contemporaneous adjustment for any usage reductions due to streetlight dimming through the network controller.

7. Audit

During the pilot's second year, PG&E will conduct an audit to determine whether actual, reported usage from the network control system's data loggers is accurate. Each participant will cooperate with PG&E, including but not limited to, providing data and information requested by PG&E (such as any changes in operating schedule), and providing access to and the ability to test the lights, circuitry and loggers and other equipment used for the operation of the participating customer's program, including information from suppliers of equipment and/or services for the participant's program. PG&E shall provide the participant with no less than 48 hours' advance notice of any intended site visit. The site visit will be scheduled during the standard work week, between 8 AM and 2 PM. At its own expense, the Customer may attend and observe the field audit.

a. All participants will meet after audit to: evaluate the first year of the pilot program, discuss proposing any mid-term adjustments, and begin to discuss potential longer-term billing solutions (cost, structure, etc.), if data logger output has been found to be consistent with both Rule 17 and Direct Access standards (DASMMD). Audit requirements and basic outline are included in Attachment 1.

b. At the sole discretion of the participating customer, the participant may also test data logger devices to ensure proper reporting of energy consumption (e.g. whether it is recording data to within +/- 2% accuracy). The participant will also monitor its software reports for anomalies (e.g. system alarm and error messages). If any of the participant's tests or monitoring ever reveals any such anomalies, within 5 days the participant shall report such findings to PG&E.

8. Conditions of Service

a. Missing, Inaccurate or Otherwise Unusable Data

i. If during monthly operation of the pilot PG&E determines that more than 5% of the expected data logger readings of the electrical usage are either missing, inaccurate, or otherwise unusable, PG&E will alert the participating customer of the specific streetlights and records involved. If the nature of the problem is data-related, such participating customer will have 5 days to provide the data in question or demonstrate that the problem is not on the customer side. If the nature of the problem is hardware related, PG&E will afford such participating customer two weeks to test its equipment (control and luminaire) and review its maintenance records. The participant shall provide PG&E with the results of its test and other efforts, in writing. Until any such data-related or hardware-related problems are cured, PG&E shall bill the problem service accounts at the standard LS-2 charges and fixed kilowatt hour amounts, without adjustment. When the customer is able to demonstrate that the problem service accounts have been cured, PG&E will once again adjust those bills in accordance with the data logger readings. If the customer is able to demonstrated to PG&E's satisfaction that the problem relates solely to PG&E's processing of participant data, PG&E will adjust the participating customer's bill in accordance with the participant's usage reports when the next bi-monthly bill adjustment is made.

ii. If more than 5% of the expected data logger readings continue to be missing, inaccurate or otherwise unusable for any 4 months or greater period (either consecutive or not) during any 12 month period within the pilot's term, PG&E reserves the right in its sole discretion to suspend pilot participation for that participant. The participant may seek reinstatement through demonstration of resolution of these deficiencies.

iii. If during monthly operation of the pilot PG&E determines that less than 5% of the expected data logger readings of the electrical usage are either missing, inaccurate, or otherwise unusable, PG&E will notify the customer that they have 5 days to provide the data in question or demonstrate that the problem is not on the customer side. During this period PG&E will delay issuing the customer's adjusted bill with the expectation of data submission. If PG&E has not received the requested data within this 5-day period, PG&E will bill the customer at the standard LS-2 charges and fixed kilowatt hour amounts. If the data is provided after this bill, PG&E will credit the customer in a subsequent bill. If the participant is able to demonstrate to PG&E's satisfaction that that the problem relates solely to PG&E's processing of the participant's data, PG&E will make the adjustment for that participant on the basis of logger readings supplied by the participating customer.

iv. Should the audit reveal that, based on PG&E's actual administrative costs during the audit period, the projected total pilot costs are likely to exceed $150,000 before the pilot concludes, PG&E and the participants will reach an agreement on a cost-sharing arrangement relating to the expected administrative costs per month to participate during the remainder of the pilot. If the parties cannot agree on mutually acceptable terms for cost-sharing, the participating customers have the option of withdrawing from the pilot, and PG&E has the option of suspending participation for such participants.

v. Within a reasonable time after completion of the audit, PG&E will provide the pilot participants with a status report on PG&E's actual costs for the pilot to date and its projected costs to administer the pilot for the remainder of its term. Thereafter, PG&E shall provide to all participants, upon the request of any participant, a similar status report on total pilot costs, up to a maximum of one such report per quarter.

vi. In circumstances where pilot participants pay PG&E's administrative costs after PG&E total expenditures has reached $150,000, PG&E will submit to each participant a separate statement reflecting the agreed monthly administrative costs for that participant's continued participation in the pilot. As to any participant that does not pay such costs in a timely manner, PG&E may, in its sole discretion, suspend participation for any participant and bill without adjustment under LS-2 during that period. If and when the participant later pays such costs, PG&E shall resume making adjustments for the next bi-monthly adjustment period.

vii. Missing, inaccurate and unusable data on electrical consumption shall be deemed to include:

<u>Missing</u>: The participant did not deliver expected read(s) for a data logger in service for that streetlight.

<u>Inaccurate</u>: The read delivered by the participant yielded a usage value outside anticipated tolerance on high / low validation

<u>Unusable</u>: The read delivered by the participant was not usable in PG&E's calculation process (e.g., expected 5 dial read received 4 dial, etc.)

b. **Audit Results:** If the results of PG&E's audit of the data loggers or readings within the customer's system indicate that the data previously used to credit the participant was inaccurate or otherwise unusable, PG&E reserves the right to suspend the pilot for that participant, and bill that participant at the standard LS-2 charges and fixed kilowatt hour amounts, including retroactive billing, for any period previously credited up to 3 years consistent with CPUC rules. PG&E will meet and confer with the participant before taking this action. If the participant is able to demonstrate, to the satisfaction of PG&E, that the problem with the data logger has been corrected, and the participant wishes to resume participation in the pilot, the participant shall be reinstated.

c. **Overall Term of Pilot Agreement:** Unless otherwise terminated or suspended by operation of other provisions, the agreements under pilot program shall expire at the end of three years or when the CPUC issues a final decision in Phase 2 of PG&E's 2014 General Rate Case, whichever comes later.

8. Request for CPUC Adoption

PG&E will prepare, circulate and, once signed, file a non-precedential Settlement Agreement under Rule 12.1 which would resolve all Streetlight issues in PG&E's 2011 GRC Phase 2, and would reference support for approval of the Advice Letter and prompt implementation of the pilot program's special contract for unmetered service under LS-2 for participating cities. Time is of the essence for implementation of the pilot program given that at least one participating city, San Jose, is expected to begin installation of a network controlled system in or before August 2011. Therefore, the parties to this Settlement may request that the CPUC expedite the effective date of the Advice Letter implementing this network controlled streetlight pilot program, and if the CPUC believes it to be necessary, expediting approval of this settlement. All Settling Parties, including the Cities of San Jose and Oakland, agree to support CPUC approval of the Motion for Adoption of this Settlement as well as the Advice Letter agreed to herein for prompt implementation of the pilot program.

10. Participants' Option to Opt Out

If, for any reason, a participant determines that it is not in its interest to continue its participation in the pilot, it retains the right to opt out subject to the following conditions. Before it may opt out, a participant must first provide written notice to PG&E of its decision to opt out, and PG&E shall retain all of the participants' network controlled streetlights to their existing non-controlled light by lamp type and bill them under Schedule LS-2 in accordance with PG&E Rule 12 provisions for rate changes (i.e., effective the next bill cycle). Once a participant opts out of the pilot, it may not return to service under the pilot for a year, also in accordance with Rule 12. Even after opting out, the pilot participant shall provide PG&E with requested documentation reasonably necessary for PG&E to conduct an audit and evaluate the pilot.

APPENDIX A – REQUIREMENTS
PG&E's DATA, SCHEDULING & AUDIT REQUIREMENTS for PILOT

I. DATA SUBMITTAL REQUIREMENTS

To be eligible for streetlight control billing credits, participating cities must submit monthly data files to PG&E (based on Detailed Schedule for Data Reporting discussed in the term sheet above as well as set forth below) that each contain:

A. Mandatory Data Fields for Monthly Reporting

(i) Base Data Fields from PG&E Records -- Provided Initially by PG&E but Included with Each Month Report by Customer

1. PG&E Account ID: Provided for each streetlight data row
2. PG&E Service Agreement ID (SAID): Provided for each streetlight data row
3. PG&E Service Point ID: Provided for each streetlight data row
4. Streetlight ID: The current PG&E or Agency assigned pole number identifying streetlight(s) with controls matching Badge Number included in PG&E billing record, required condition of LS-2 service.

(ii) Data Supplied with Each Monthly Report by Customer:

1. Install Date: The date the streetlight control was installed.
2. Wattage Rating of Control: The total wattage of installed control and monitoring equipment. <Required for energy use adjustment if control does not monitor own use and if control uses more than 1.0 Watt. Will be disregarded if control tests show less than 1 watt or if control reports its own use.>
3. Lamp Wattage and Type: The type of fixture installed and wattage of the installed lamp (PG&E will adjust for ballast wattage if applicable, does not apply to LED or Induction).
4. Individual Day: To facilitate the most accurate possible adjustment for the customer for the measurement period, and to avoid proration issues if a rate change occurs during the quarter, data for each lamp is to be reported for each individual day within the reporting period.
5. Read Date/Time: Date (MMDDYYYY) and time (HHMMSS) of each daily read for the reporting period.
6. Period Read: Native, unaltered cumulative watt hour reading from control system for the measurement period; or native, unaltered usage value for the measurement period and all succeeding usage values for entire measurement period.
7. Equipment Changes: Agency will report any change to equipment during the period, including lamp size, fixture, or monitoring and control changes, and all information included in items 1 - 6 above.

B. PG&E Manual Adjustment of Billing -- Monthly

- Per detailed schedule in Section II, PG&E will calculate elapsed KWH usage for measurement period, and apply tariff charges to produce adjustment (may increase bill during winter months).
- Where report data can't be validated due to data errors, or other technical issues, the base monthly tariff billing per lamp will be billed. If missing data is subsequently made available within the period specified in Rule 17.1, billing adjustments will be made based on reported data.

Additional Required Information

1. Group or Schedule Code: If participating customer operated multiple streetlights on similar dimming schedules, providing intended operating schedule assignment in group code form for each streetlight enhances audit/data quality assurance, for verification of actual operation/use to Agency's intended use.
2. Other System Collected Data: Upon request and assuming vendor system can provide it, PG&E is entitled to also receive Power (wattage), calculated burn hours, amperage, and voltage for each light, as well as certain system generated status, alarm, fault, or exception telemetry that would assist PG&E in verifying data accuracy.

II. Detailed Schedule for Data Reporting (for Monthly Billing Adjustments)

1. PG&E and the customer will agree on a monthly billing cycle for the new Service Agreement and Account for lights included in this pilot program. Processes will be implemented so that billing for the new Service Agreement and account will be made based on the following schedule for each billing cycle: PG&E and the customer will agree on a monthly "Bill Cycle." The Bill Cycle will be established, corresponding to PG&E metered account bill cycles, where the period covered by the cycle will be approximately 30 days, and may vary from 27 to 33 days.

2. Following the close of the "Billing Window" (see 4 below) of the prior month Bill Cycle, PG&E will place a "hold" on the account so that a standard automatic calculation of billing based on standard LS-2 lamp rates will not be performed.

3. For inclusion of newly retrofit lamps in the adjustment for the current "Bill Cycle" Customer must report changes by close of business on the fifth (5th) calendar day prior to the last day of the Bill Cycle. (For example, if the last day of the Bill Cycle is April 19th, the last day for the customer to be able to report a change is April 15th.)

4. The "Billing Window" for the Account and Service Agreement will be 10 days, and will start on the closing day of the Bill Cycle.

5. Customer must report data from its control and monitoring system to PG&E within 1 day of the close of the Bill Cycle.

6. PG&E will perform data validation processing and adjustment calculations, and provide the customer with notification of missing or unusable data (if any) within the next 5 days. The close of business on the 5th day following submission of customer data (the sixth day of the Billing Window) is the deadline for any adjustments to data, and standard LS-2 energy charges will apply for any light for which usable data is not received.

7. One day prior to the close of the Billing Window, PG&E will release the "hold" placed on the account so that billing may proceed.

8. The bill for the Account and Service Agreement included in the pilot program will be produced and mailed within 2-3 days of the close of the Billing Window.

III. AUDIT REQUIREMENTS

During pilot's second year, PG&E will audit data logging/reporting accuracy, including but not limited to the following:

1. Customer will provide appropriate vendor documentation, such as specification sheets, applicable certification testing and compliance documentation, 3rd party evaluations, etc., for each vendor technology. This will also include any data security studies and documentation detailing system data integrity features and performance.
2. PG&E will require a small number (to be determined and agreed upon later) of samples of each vendor control and monitoring technology for testing by PG&E.

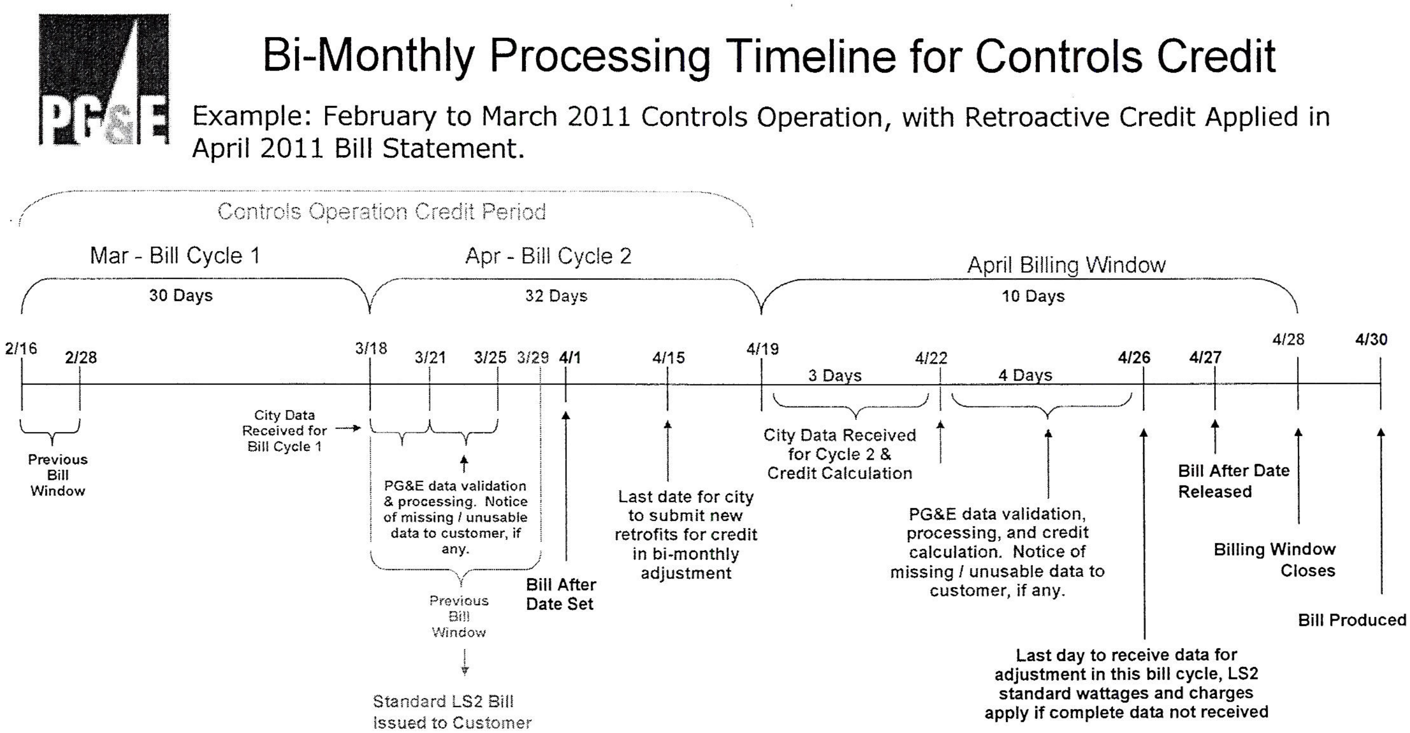
3. Customer will provide, at PG&E's request, periodic on-site access to vendor system during the audit period to verify that system-resident readings for selected streetlight sample agrees with submitted readings.
4. PG&E may field-verify a sample of installed fixtures during the audit period to ensure a) fixture type and wattage agrees with the Customer's data file, and b) existence of control/monitoring devices there.
5. PG&E shall evaluate whether the network control system's data loggers meet utility revenue quality standards under both Rule 17 and the Direct Access standards (DASMMD).

After audit is complete, all participants will meet to:

- Evaluate the first year of the pilot program
- Discuss proposing any mid-term adjustments to the pilot, and
- Begin to discuss potential longer-term billing solutions, the nature of which will depend on whether the data loggers have been found to meet both Rule 17 and Direct Access standards (DASMMD).

APPENDIX B

Network Controlled Dimmable Streetlight Pilot Timeline



(END OF APPENDIX D)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON SCHEDULE ES AND NATURAL GAS BASELINE QUANTITY RESIDENTIAL RATE DESIGN ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Settlement Agreement agree on a mutually acceptable outcome regarding Schedule ES (ES) and Natural Gas Baseline Quantity (GBQ) rate design issues -- two out of three of the remaining rate design issues[1] for the residential class[2] -- in Application (A.) 10-03-014, Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.

This Schedule ES and Gas Baseline Quantity Settlement (ES/GBQ Settlement) is supplemental to the Settlement on Marginal Cost and Revenue Allocation issues in Application (A.) 10-03-014, filed with the CPUC on March 14, 2011 (March 14 MCRA Settlement), in that it addresses two out of the three remaining residential issues that were not resolved in the March 14 MCRA Settlement and have not already been litigated in this proceeding. The ES/GBQ Rate Design Settling Parties (Settling Parties) intend that the complementary outcomes of this ES/GBQ Settlement and the March 14 MCRA Settlement be consolidated in the Commission's final decision in this proceeding. The details of this ES/GBQ Settlement are set forth below.

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[1] The bulk of PG&E's electric rate design proposals for the Residential class have already been litigated, briefed, and are the subject of Decision (D.) 11-05-047 issued on June 2, 2011. The remaining residential rate design issues in Phase 2 of PG&E's ongoing 2011 General Rate Case proceeding are: (1) natural gas baseline quantities, (2) the Schedule ES multifamily master meter discount, and (3) the Schedule ET mobile home master meter discount. Of these three issues, the first two, which were uncontested in testimony, are the subject of this Settlement Agreement. Only the third issue (Schedule ET mobile home master meter discount) is contested, and remains so despite the parties' efforts at settlement thus far. Accordingly, the single unresolved Schedule ET residential rate design issue will be the subject of rebuttal testimony due June 24, 2011 and surrebuttal testimony due July 8, 2011. The parties expect that such rebuttal and surrebuttal testimony will be followed by further settlement discussions on ET discount issues in early to mid-July, prior to hearings which, if necessary, are scheduled for July 25.

[2] PG&E's Residential customer class encompasses and is defined as: Schedules E-1, EL-1, EM, EML, ES, ESL, ESR, ET, ETL, E-6, EL-6, E-7, EL-7, E-8, EL-8, E-9A and E-9B. The Remaining Residential issues addressed herein, and the schedules to which they relate, are as described in PG&E's January 7, 2011 update Exhibit (PGE-14) Chapter 3. The remaining gas baseline issue would apply to all applicable residential gas rate schedules.

II. REMAINING RESIDENTIAL RATE DESIGN SETTLING PARTIES

The ES/GBQ Settling Parties are as follows:[3]

- Pacific Gas and Electric Company (PG&E)
- The Utility Reform Network (TURN)

III. ES/GBQ SETTLEMENT CONDITIONS

This Settlement resolves the issues raised by the ES/GBQ Settling Parties in A.10-03-014 on these two residential rate design issues, subject to the conditions set forth below:

1. This ES/GBQ Settlement embodies the entire understanding and agreement of the ES/GBQ Settling Parties with respect to the matters described (natural gas baseline quantities and Schedule ES discount), and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the ES/GBQ Settling Parties with respect to those matters. This ES/GBQ Settlement incorporates the March 14 Settlement by reference.

2. This ES/GBQ Settlement represents a negotiated compromise among the ES/GBQ Settling Parties' respective litigation positions on the matters described, and the ES/GBQ Settling Parties have assented to the terms of this Settlement only to arrive at the agreement embodied herein. Nothing contained in this ES/GBQ Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the ES/GBQ Settling Parties on these matters in this proceeding. This ES/GBQ Settlement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.

[3] PG&E and TURN have been in communication with the Division of Ratepayer Advocates (DRA) and are informed and believe that the DRA does not oppose this ES/GBQ Settlement.

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

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

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

6. The ES/GBQ Settling Parties shall jointly request Commission approval of this ES/GBQ Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required,[4] briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The ES/GBQ Settling Parties intend the ES/GBQ Settlement to be interpreted and treated as a unified, integrated agreement incorporating the March14 MCRA Settlement. In the event the Commission rejects or modifies this ES/GBQ Settlement, the ES/GBQ Settling Parties reserve their rights under CPUC Rule 12.4.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The overall procedural and settlement history of A.10-03-14 is set forth in Section IV of the March 14 MCRA Settlement, to which this settlement is supplemental, and which is incorporated herein by reference.

VI. REMAINING RESIDENTIAL RATE DESIGN SETTLEMENT TERMS

A. General Terms

The ES/GBQ Settling Parties agree that the primary purpose of rate design for the residential customer class is to take the revenue allocations reached in the March 14

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[4] Any oral and written testimony that the CPUC might require may be prepared jointly among parties with similar interests.

Settlement and ensure that they are fully recovered through residential rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the March 14 MCRA Settlement, and reflects a reasonable compromise of parties' proposals on these subjects.

The ES/GBQ Settling Parties agree that it is reasonable for the CPUC to adopt the natural gas baseline quantities and the electric master meter discount for Schedule ES set forth below. The ES/GBQ Settling Parties agree that the actual total rates derived at the time of implementation of this ES/GBQ Settlement, once adopted by the CPUC, shall be designed on an overall revenue-neutral basis to collect the then-current revenue assigned to the Residential class.

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

The ES/GBQ Settling Parties further agree that this ES/GBQ Settlement resolves all Remaining Residential rate design issues in A.10-03-014, other than Schedule ET mobile home park master meter discount rate design which is still contested.

B. Remaining Residential Settlement Terms

1. Natural Gas Baseline Quantities

The ES/GBQ Settling Parties agree that it is reasonable for the CPUC to adopt PG&E's uncontested proposals for natural gas baseline quantities as set forth in Attachment 1, and as described in Exhibit 14, Chapter 3, page 3-4 line 9 through Table 3-6 on page 3-8 (see excerpted table set forth in Attachment 1 to this ES/GBQ Settlement Agreement). These gas baseline quantities are based on four years of recorded data, from November 2005 through October 2009, and are set at the upper end of the legislated ranges set forth in Public Utilities Code Section 739. These natural gas baseline quantities, together with any revenue neutral rate adjustments, will be implemented in one step on the first day of the next available season after the effective date of the final decision adopting this Settlement – either April 1 or November 1.

2. Electric Master Meter Discount for Schedule ES

The ES/GBQ Settling Parties agree that it is reasonable for the CPUC to adopt a revised version of PG&E's proposals for the Schedule ES discount -- which relates to electric multifamily service master metered customers (set forth in Exhibit 14, Chapter 3, Table 3-11 on page. 3-14, and explained at page 3-9 line 14 through page 3-13 line 18). TURN's testimony identified several modifications to the master meter discount calculation for Schedule ET that also apply to Schedule ES. No other party took a position on the Schedule ES discount. This settlement therefore is a compromise of TURN's and PG&E's positions relating to Schedule ES in this proceeding.

Specifically, the ES/GBQ Settling Parties agree it is reasonable for the CPUC to adopt the revised Schedule ES Master Meter Discount discussed below, for a base discount of **$2.32** per space per month. The Settling Parties have agreed to revise and update PG&E's originally proposed ES Base Discount calculation (from line 32 of Table 3-13 in the above-cited testimony) as follows:

1. The revised base ES discount recognizes that the equipment costs for a master meter are greater than for a residential meter, and thus the settlement calculation uses a medium light and power (ML&P) meter at secondary voltage as a proxy for the master meter.
2. Primary and secondary distribution costs have been removed from the connection costs used in developing the revised base ES discount, to be consistent with PG&E's marginal customer access cost methodology.
3. Transformer and service equipment costs and related ongoing costs for both the tenant meter and master meter have been removed from the revised base ES discount, because tenant service and transformer costs are not avoided and no offset for these costs is needed for the master meter. Whether master metered or individually metered, the service extension termination point is typically the same. What differs is whether the connection termination point is at a single master meter or multiple residential meters in a grouped configuration.
4. For ongoing costs used in developing the revised base ES discount, adjust "Other Account 903" expenses that are included in the billing and collection cost category for the tenant meters to reflect as avoided costs only the costs for Account Services, Local Office Transactions and Neighborhood Payment Centers.

5. For ongoing costs for the master meter, applied meter services costs and meter reading costs consistent with the ML&P proxy for the master meter; apply the billing and collections costs consistent with a small light and power (SL&P) meter to reflect the billing process for a master metered multi-family development as compared to the billing of ML&P customers.

Attachment 2 provides conforming calculations to update the Table 3-13 derivation of the Schedule ES submetering discount.

To determine a Net ES Discount, the revised Base ES Discount agreed to in the Settlement, once adopted, must be adjusted to reflect the Diversity Benefit Adjustment. The Diversity Benefit Adjustment will need to be recalculated using rates in effect at the time the ES submeter discount is implemented, and should be set to the Diversity Benefit Adjustment calculated for PG&E Schedule ET multiplied by a factor of 58 percent. Thus, although the Base Discount proposal the CPUC adopts here will go into effect for this rate case cycle as proposed, without further modification, the *Net* ES Discount figures set forth here are merely illustrative:

Base Monthly ES Discount:	$ 2.32
Less Diversity Benefit Adjustment:	$ 2.86[5]
Net ES Discount:	$ (0.54)

The effective date for the finally calculated new Net ES Master Meter Discount shall generally be the same as the effective date for the non-residential rate design changes to be implemented as a result of the 2011 GRC Phase 2 proceeding.

VII. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the March 14 MCRA Settlement, Term VIII. Subsections 2 and 3, shall apply to this ES/GBQ Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This ES/GBQ Settlement shall become effective among the ES/GBQ Settling Parties on the

5 This $2.86 figure is merely illustrative. The final figure will be 58% of the Diversity Benefit Adjustment adopted by CPUC for Schedule ET as implemented in rates pursuant to this proceeding.

date the last Settling Party executes the ES/GBQ Settlement, as indicated below. In witness whereof, intending to be legally bound, the ES/GBQ Settling Parties hereto have duly executed this ES/GBQ Settlement on behalf of the ES/GBQ Settling Parties they represent.

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ATTACHMENT 1

Natural Gas Baseline Quantities

	SUMMER Proposed	WINTER Proposed	SUMMER Proposed	WINTER Proposed
	G-1, G-S, G-T (and CARE)		GM (and CARE)	
TERRITORY	Therms per Day		Therms per Day	
P	0.46	2.18	0.33	1.06
Q	0.65	2.02	0.59	0.79
R	0.43	1.82	0.36	1.26
S	0.46	1.92	0.33	0.66
T	0.65	1.79	0.59	1.12
V	0.69	1.79	0.56	1.22
W	0.46	1.69	0.29	0.89
X	0.59	2.02	0.36	0.79
Y	0.82	2.64	0.49	1.06

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
SCHEDULE ES SUBMETER DISCOUNT

Line No.	Submeter Discount - ES	*Avoided Costs per Tenant Meter*	*Costs for Master Meter*	
1	Connection Costs (2003 $)			
2	Eng. & Mapping	$ -	$ -	
3	Transformer	-	-	
4	Service	-	-	
5	Meter	82.45	426.98	
6	Transformer/Service/Meter (TSM) Equip. Cost	$ 82.45	$ 426.98	
7	Escalation to Test Year (2011)	1.6602	1.6602	
8	Escalated TSM Equipment Cost	$ 136.88	$ 708.87	
9	RECC	9.94%	9.94%	
10	Annualized Connection Equipment Cost — Annual Finance, Tax, Insurance & Depreciation	$ 13.61	$ 70.47	
11	Test Year Secondary Dist. ($/kW-Yr)	$ -		
12	Test Year Ongoing Costs Per Meter			
13	Meter Services	$ 3.29	$ 152.47	
14	Transformer Maintenance	-	-	
15	Service Maintenance	-	-	
16	Meter Reading	(4.21)	43.19	
17	Billing & Collections	24.87	94.90	
18	Total Ongoing Costs Per Meter	$ 23.95	$ 290.57	
19	Total Connection Cost	$ 37.56	$ 361.04	
20	Average Number Dwelling Units		37.00	
21	Master Meter Connection Cost Dwelling Units		$ 9.76	
22	Net Marginal Connection Cost Per Dwelling Unit	$ 27.80		
23	Uncollectibles Factor	0.2853%		
24	Uncollectibles	0.08		
25	Net Base Discount Per Dwelling Unit — Annual	27.88		
26	**Base Submeter Discount Per Dwelling Unit — Monthly**	**$ 2.32**		
27	Diversity Benefit Adjustment *(Illustrative)*	2.86	*58% of ET Diversity*	
28	Secondary Line Loss Adjustment	-		
29	*Illustrative* Net Discount (Monthly)	$ (0.54)		
30	*Illustrative* Net Discount (Daily)	$ (0.01760)		
31	**Base Submeter Discount — Daily Equivalent**	**$ 0.07634**		

(END OF APPENDIX E)

SUPPLEMENTAL SETTLEMENT AGREEMENT ON AGRICULTURAL RATE DESIGN ISSUES IN PG&E'S APPLICATION 10-03-014

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Agricultural (Ag) Rate Design Settlement Agreement (Ag Settling Parties) agree on a mutually acceptable outcome to the rate design issues for the Ag class[1] in Application (A.) 10-03-014, of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.

This Ag Settlement is supplemental to the Settlement in A.10-03-014 filed with the CPUC on March 14, 2011 (March 14 Settlement), in that it uses the revenue allocation agreed to in the March 14 Settlement and addresses Ag rate design issues that were not resolved in the March 14 Settlement. The Ag Settling Parties respectfully request that the Commission consolidate its decision on this Ag Settlement with its decision on the March 14 Settlement because this Ag Settlement is an extension of and is complementary to the March 14 Settlement Agreement. The details of this Ag Settlement are set forth herein.

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[1] The Ag customer class encompasses and is defined as PG&E customers taking service under Schedules AG-1A/B, AG-4A/B/C, AG-5A/B/C, AG-RA/B, AG-VA/B, and AG-ICE, as described in Exhibit (PG&E-14) Chapter 6. Schedule E-37 is implicitly part of the agricultural class even though Schedule E-37 customers are not agricultural customers. Rate design and rates for Schedules AG-5B and E-37 are identical and are based on the combined billing determinants of Schedule AG-5B and Schedule E-37 customers.

II. AG SETTLING PARTIES

The Ag Settling Parties[2] are as follows:

- Agricultural Energy Consumers Association (AECA)
- California Farm Bureau Federation (CFBF)
- Energy Producers and Users Coalition (EPUC)
- Pacific Gas and Electric Company (PG&E)
- South San Joaquin Irrigation District (SSJID)

III. AG SETTLEMENT CONDITIONS

This Ag Settlement resolves the issues raised by the Ag Settling Parties in A.10-03-014 on Ag rate design, subject to the conditions set forth below:

1. This Ag Settlement embodies the entire understanding and agreement of the Ag Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Ag Settling Parties with respect to those matters. This Ag Settlement supplements and is an extension to the March 14 settlement filing, and thus incorporates by reference the terms, boilerplate and all language of that document.

2. This Ag Settlement represents a negotiated compromise among the Ag Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of this Settlement only to

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2 Although they are not signatories to the Ag Settlement, the California Large Energy Consumers Association (CLECA), Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN) participated in the Ag settlement conferences to monitor for potential revenue allocation effects on other classes. These three parties have indicated that they do not oppose the Ag Settlement.

arrive at the agreement embodied herein. Nothing contained in this Ag Settlement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Ag Settling Parties on these matters in this proceeding. Pursuant to Rule 12 of the Commission's Rules of Practice and Procedure, this Ag Settlement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.

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

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

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

6. The Ag Settling Parties shall jointly request Commission approval of this Ag Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required,[3] briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

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[3] Any oral or written testimony that the CPUC might require may be prepared jointly among parties with similar interests.

7. The Ag Settling Parties intend the Ag Settlement to be interpreted and treated as a unified, integrated agreement incorporating the March 14 Settlement, which forms the foundation for the Ag rate design agreed to herein. In the event the Commission rejects or modifies this Ag Settlement or the underlying March 14 Settlement, the Ag Settling Parties reserve their rights under CPUC Rule 12.4.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The overall procedural and settlement history of A.10-03-014 is set forth in Section IV of the March 14 Settlement on Marginal Cost and Revenue Allocation (MCRA) issues in this proceeding. This supplement to the March 14 settlement filing incorporates by reference the terms and boilerplate language of that document.

V. AG SETTLEMENT TERMS

A. General Terms

The Ag Settling Parties agree that the primary purpose of rate design for the Ag class is to take the revenue allocations reached for this class in the March 14 Settlement and ensure that they are fully recovered through Ag rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the March 14 Settlement, and reflects a reasonable compromise of Ag Settling Parties' proposals.

The Ag Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Tables 1 and 2 of the March 14 Settlement, which were based on the January 1, 2011 effective rates and revenue requirements. The Ag Settling Parties agree that the actual rates derived at the time of implementation of this Ag Settlement, once adopted by the CPUC, shall be designed to collect the then-current revenue, modified as prescribed by the MCRA Settlement Agreement.[4] Adopted revenue requirements in effect at the time of settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates that will result when the Phase 2 rate changes are implemented will vary from those shown in Exhibit A. However, these actual rates shall be based on the rate design methods described in this Ag Settlement Agreement.

The Ag Settling Parties agree that all testimony served prior to the date of this Ag Settlement that addresses the issues resolved by this Ag Settlement should be admitted into evidence without cross-examination by the parties. However although PG&E believes that at most a protest to the filed Ag Settlement and a corresponding response are necessary to dispose of any contested issues and approval of the Ag Settlement in full, in the event the ALJ orders new testimony or hearings on such issues, testimony on contested Ag Settlement issues, and only those issues, would be subject to cross-examination.

The Ag Settling Parties further agree that this Ag Settlement resolves all Ag rate design issues in A.10-03-014.

B. Ag Settlement Rates

1. Illustrative Ag Settlement Rates

The Ag Settling Parties agree that rates to collect the revenue allocated to the Ag customer classes under the March 14 Settlement shall be designed consistent with the illustrative rates set forth below and in Exhibit A, for Schedules AG-1A/B, AG-4A/B/C,

[4] *See also* Ag Settlement's methodologies relating to revenue allocation issues, in sections of this Settlement further below.

AG-5A/B/C, AG-RA, AG-RB, AG-VA, AG-VB, and E-37.[5] The agreed basic rate designs reflect the MCRA Settling Parties' prior agreement, in the March 14 MCRA Settlement, to a 1.5 percent increase to all schedule average total rates for the agricultural class.

The Ag Settling Parties further agree that the same methods used to determine the illustrative rates provided herein will be applied to the revenue requirement in effect when this Settlement is implemented, as described in Section A. above.

2. Methods Used To Develop Illustrative Settlement Rates

The Ag Settling Parties agree that the basic rate designs for each of the applicable Ag rate schedules will be updated upon implementation of this Ag Settlement using the methods underlying development of the illustrative settlement rates for Schedules AG-1A/B, AG-4A/B/C, AG-5A/B/C, AG-RA, AG-RB, AG-VA, AG-VB, and E-37 set forth in this supplemental Ag Settlement Agreement.

The Ag Settling Parties agree that customer charges for all Ag schedules will increase by 20 percent for all AG-A and AG-B rate schedules, but that AG-4C and AG-5C will remain at their current level. The Ag Settling Parties agree that demand charges and connected load charges shall generally increase by 5 percent, except in certain cases implicit in Exhibit A where distribution and generation revenue assignments to demand charges do not allow a 5 percent increase. The Ag Settling Parties agree that unbundled

[5] The Lamont PUD proposed to allow non-Ag water pumping accounts to be eligible for Schedule E-37, which, although it is not an Ag rate schedule, currently serves oil pumping customers whom Lamont asserted may have certain similarities with other non-Ag water pumping accounts. Thus, this E-37-related issue was the subject of a compromise set forth in this Ag Settlement. In addition, this Ag Settlement does not include AG-ICE rate design, which is handled separately through annual advice letters, pursuant to D.05-06-016, as stated at pages 6-4 to 6-5 of Exhibit (PG&E-14).

energy charges will be set residually, based on current Distribution and Generation seasonal and Time-Of-Use (TOU) relationships

The above methods shall be used to set initial rates upon implementation of this settlement at then-current revenue requirements using the MCRA Settlement Agreement's revenue allocation principles. All subsequent rate changes until a decision in the next GRC Phase 2 proceeding shall be governed by the principles set forth in the March 14 MCRA Settlement in Section VIII, Section 3, for Rate Changes Between GRCs, except to the extent necessary to assure that all subsequent rate changes adhere to the TOU revenue neutrality methodology set forth in this Ag Settlement (*see* Section 3 below).

3. TOU Revenue Neutrality

The Ag Settling Parties agree that it will be reasonable to adjust the revenue amounts assigned to the AG-4A and AG-4B rate schedules (or other destination TOU rate schedules) over the course of the 2011 General Rate Case cycle to account for those revenue shortfalls that result as current AG-1A and AG-1B customers are reassigned to TOU rate schedules. The revenue adjustment amount will be symmetric if there are net revenue increases rather than revenue shortfalls due to TOU migration. Similarly, the adjustments will be based on all default TOU migrating customers, and will not use only those who saved on their new TOU rate. The adjustments will track those revenue shortfalls that result strictly from structural differences between the current groups of non-TOU versus TOU agricultural rate schedules, net of any shortfalls that should be attributed to customer TOU usage shifts in response to their assignment to TOU rate schedules.

Illustrative revenue adjustments for AG-1A customers defaulting to AG-4A and for AG-1B customers defaulting to AG-4B, for achieving revenue neutrality, are shown in the Excel file *Ag-PGE-Settlement-TOU-Adjust.xls* (provided as Exhibit B hereto) The revenue shortfall amounts will be calculated annually based on 12-month record periods ending September 30, and then applied as adjustments to the following year's rates as set in PG&E's Annual Electric True-Up (AET) proceeding.

The Settling Parties agree that the TOU revenue-neutrality adjustments will be made using the following methodology:

1. The revenues that would have been billed to the migrating customers under both the pre-migration schedule and their new TOU schedules will be calculated. The net difference, accounting for both positive and negative revenue amounts, will be used to develop the initial or "nominal" shortfall amounts for each TOU schedule.

2. A comparison of the pre-migration and post-migration TOU load shapes for the migrating customers will be used to estimate the change in revenue due to load shapes. Any changes in revenues due to TOU load shape changes will be used to adjust the nominal revenue shortfalls for each TOU schedule, resulting in the Adjusted Shortfall Amounts to be applied as adjustments in the AET. For customers migrating to AG-4B, AG-5B (if applicable), or AG-5C (if applicable), these adjustments will also consider changes in revenues attributable to changes in summer on-peak demand utilization.

3. The "original peak TOU shares" of the migrated customers (and original ratios of summer-season kWh to on-peak kW, for the customers migrating to AG-4B, AG-5B, or AG-5C) will be calculated using actual peak-period TOU shares and demand utilization ratios from the 12-month period before the customers were assigned to their new TOU rate. For each subsequent year, the baseline usage will be from the 12 months prior to the migration, even if a migrated customer has been on a TOU schedule for more than a year.

4. Revenues associated with peak day pricing discounts and revenues shall be excluded from this analysis.

5. The TOU revenue-neutrality adjustment will only apply to load billed before the 2014 GRC Phase 2 rates take effect. Settling Parties anticipate that adjustments will be applied only to the 2014 and 2015 AET rates. The 2014 AET adjustment will reflect those customers assigned to new TOU rates in 2013, and will reflect

usage of these customers for the period from March 1, 2013 to September 30, 2013 (using bills issued during the month of September). The 2015 AET adjustment will reflect usage for the period starting October 1, 2013 (using bills issued during the month of October) and continuing to the effective date of rate changes in Phase 2 of PG&E's 2014 GRC or September 30, 2014, whichever is later.

6. Each year, on approximately November 1 but no later than November 15, PG&E will provide the Agricultural representatives as well as CLECA, DRA, EPUC and TURN and any requesting parties with workpapers and analyses used to determine the revenue shortfall to be included in the final AET to be filed in late December of that year. These data will include a comparison of the migrated customers' aggregate current and prior-to-migration year's loads and load shapes, a comparison of the loads and load shapes for the same years for the non-migrating customers who are on the target schedule (e.g. Schedule AG-4A), and the workpapers corresponding to the example spreadsheet used to estimate the revenue loss. If requested, PG&E will confer with the Agricultural representatives to discuss the results before filing of the final AET.

7. If the summer on-peak TOU load shares of the non-migrating customers on the applicable schedules lie within the following deadband ranges, it will be assumed that the underlying Agricultural electricity consumption conditions are sufficiently unchanged that the approach described in Paragraphs 1 through 6 of this section can be used without further adjustments:

AG4A:	11.3 percent, plus or minus 0.5 percent (10.8%-11.8%)
AG4B:	15.7 percent, plus or minus 0.5 percent (15.2%-16.2%)

If the summer on-peak TOU load shares are outside of the deadband, PG&E and the Agricultural representatives will confer to evaluate whether underlying consumption conditions may have changed sufficiently that the adopted methodology needs to be reviewed. (Deadbands will not be defined separately for AG5B or AG5C, but the review would also encompass these adjustments, if there are migrating customers who have chosen service under either of these two schedules.) CLECA, DRA, EPUC, TURN and any other requesting parties shall be notified of the results of such conference(s) if those conferences result in a recommendation to adjust the methodology. If either PG&E or the Agricultural representatives or the requesting parties believe further review is necessary, PG&E, the Agricultural representatives and those of the requesting parties' will confer for the purpose of determining an appropriate adjustment to the methodology.

4. Account Aggregation

The Ag Settling Parties agree that it is reasonable not to adopt an agricultural aggregation tariff in this proceeding as proposed by AECA. Instead the Settling Parties agree to facilitate an Agricultural Settlement Account Aggregation Study (Study), expected to be completed by the second quarter of 2013. This Study will obtain data and other information on agricultural customers' electrical usage to allow evaluation of agricultural account aggregation. The scope, framework and methodology for the Study have been expressly agreed to by PG&E, AECA, CFBF and SSJID and are set forth in detail in Exhibit C, which includes supporting documents referenced as Appendices 1 through 4, which are incorporated by reference herein.

5. Schedule E-37 Cost Study and Enrollment Closure

The Ag Settling Parties agree that it is reasonable to reject the proposal by the Lamont Public Utility District (Lamont) that non-Ag general water or sewerage pumping accounts, whose annual load factor is 50 percent or more, be eligible to take service on Schedule E-37. The Ag Settling Parties acknowledge that the original purpose of Schedule E-37 was to provide incentives to oil pumping accounts to return idle oil wells to production when California crude oil prices were low, as set forth in D.97-09-047 which created Schedule E-37 exclusively for customers whose North American Industry Classification System (NAICS) code is 211111 (crude petroleum and natural gas extraction). Further, the Settling Parties recognize that present cost of service for this type of customer should be considered as well as whether the original impetus for adding an incentive in 1997 specifically for these domestic oil pumping customers continues to apply to, or be necessary and appropriate for, all domestic oil pumping customers. The

Ag Settling Parties agree that allowing other types of non-Ag pumping customers, such as general water and sewerage pumping customers, to participate in an incentive rate that may no longer be suitable even for its original purpose, in all circumstances, would be inappropriate, absent further study and analysis as reflected in this Ag Settlement.

In addition, based on Lamont's October 6, 2010 direct testimony in this proceeding (at page 18), a revenue shortfall of up to $18.4 million would occur if the Schedule E-37 applicability language were expanded to include non-Ag water and sewerage pumping customers. Since this rate would be optional and selected by only those customers that would expect to benefit, revenue reductions would be likely. The Ag Settling Parties agree that revenue reductions that would certainly result from this option would create revenue shortfalls that would be supported by other customers, and therefore create a cost to non-participating customers. While the Ag Settling Parties acknowledge some uncertainty in the magnitude of the revenue reduction, they agree that allowing additional customers on this rate without further review of the cost basis for the rate would not be appropriate.

In summary, the Ag Settling Parties reached a compromise that, absent further review confirming that Schedule E-37 is reasonable for its original purpose and is reasonably cost-based for large non-Ag water pumping customers, the applicability of the E-37 rate should not be expanded.

The Ag Settling Parties have agreed that the following steps should occur: (a) immediately close E-37 to new enrollment, (b) provide a one-way customer option for existing E-37's to migrate to A-10, A-10-TOU, or E-19/20, (c) require PG&E to study a new cost-based E-37 industrial schedule allocation for oil and non-Ag water and sewerage pumping accounts to be filed in the 2014 GRC Phase 2, and (d) consider in the 2014 GRC Phase 2 proceeding whether E-37 should be eliminated and whether a new cost-based pumping rate, including large non-Ag pumping, should be offered. This compromise allows a more considered approach to ensure that reasonable, cost-based options are made available to non-Ag water pumping compared to simply expanding the use of a rate that was offered on a very limited basis only to oil pumping customers so that they would bring idle wells back into service as a source of domestic petroleum.

The Settling Parties agree that the requirement of item (c) above, to file a study in the next GRC, will provide the information needed to determine whether or not large non-agricultural pumping load customers should have their own rate schedule.

6. Schedule AG-R and AG-V Enrollment Closure and Phase-Out

The Ag Settling Parties agree that it is reasonable to immediately close both Schedule AG-R and AG-V to new enrollment. In addition, both schedules will be entirely eliminated on March 1, 2014 for customers with 12 months of interval data.

7. Peak Day Pricing Rate Refinements

The Ag Settling Parties agree that it is reasonable to adopt the refinements to Schedule Peak Day Pricing (PDP) rates proposed by PG&E in Chapter 6 of Exhibit (PG&E-14).

8. Other

Unless otherwise specifically agreed by the parties or addressed in this Ag Settlement Agreement above, the proposals, methods and explanations contained in Chapter 6 of Exhibit PG&E 14, served on January 7, 2011, shall be adopted for the purpose of implementing rates under this Settlement.

VI. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the March 14 MCRA Settlement, Term VIII, Subsections 2 and 3, shall apply to this Ag Settlement, unless specifically noted above.

Certain elements of this Ag Settlement Agreement will or may require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. Such structural and system changes will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The Ag Settling Parties recognize that such changes could take several months to implement.

VII. SETTLEMENT EXECUTION

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

Exhibit A

ILLUSTRATIVE AGRICULTURAL SETTLEMENT RATES

SCHEDULES AG-1, AG-R, AG-V, AG-4, AG-5 and E-37

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 1A	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	2,166,210	$5.40	11,697,531		2,166,210	$5.67	12,282,408	
Winter								
Maximum	2,122,884	$1.02	2,165,342		2,122,884	$1.07	2,273,609	
Revenue from Demand Charges			13,862,874				14,556,017	
Revenue from Demand as % of Total			22.97%				23.76%	
ENERGY CHARGE ($/kWh)								
Summer								
Total	142,237,781	$0.21282	30,271,045		142,237,781	$0.20736	29,494,344	
Winter								
Total	59,971,641	$0.16748	10,044,050		59,971,641	$0.16314	9,783,857	
Revenue from Energy Charges			40,315,095				39,278,201	
Revenue from Energy as % of Total			66.79%				64.12%	
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
Ag 1A	429,230	$14.40	6,180,911	.47310	429,230	$17.30	7,425,678	.56838
Revenue from Customer Charges			6,180,911				7,425,678	
Revenue from Customer Chrg as % of Total			10.24%				12.12%	
			60,358,880	Total Rev			61,259,896	Total Rev
							1.5%	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG RA	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	210,552	$4.84	1,019,072		210,552	$5.08	1,070,025	
Winter								
Maximum	210,552	$0.78	164,231		210,552	$0.82	172,442	
Revenue from Demand Charges			1,183,302				1,242,467	
Revenue from Demand as % of Total			22.07%				22.83%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	1,158,207	$0.37715	436,818		1,158,207	$0.39183	453,824	
Off-Peak	16,904,121	$0.13495	2,281,211		16,904,121	$0.14000	2,366,538	
Winter								
Part-Peak	2,611,673	$0.13787	360,071		2,611,673	$0.14277	372,863	
Off-Peak	4,397,326	$0.11474	504,549		4,397,326	$0.11826	520,042	
Revenue from Energy Charges			3,582,650				3,713,266	
Revenue from Energy as % of Total			66.82%				68.23%	
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
Ag RA	28,104	$14.40	404,698	.47310	28,104	$17.30	486,199	.56838
Revenue from Customer Charges			404,698				486,199	
Revenue from Customer Chrg as % of Total			7.55%				8.93%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	28,104	$6.80	191,107	.22341	28,104	$0.00	0	.00000
Revenue from Meter Charges			191,107				0	
Revenue from Meter Chrg as % of Total			3.56%				0.00%	
			5,361,757	Total Rev			5,441,933	Total Rev
							1.5%	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG VA	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	163,503	$4.86	794,623		163,503	$5.10	834,354	
Winter								
Maximum	163,538	$0.81	132,466		163,538	$0.85	139,089	
Revenue from Demand Charges			927,089				973,444	
Revenue from Demand as % of Total			22.24%				23.01%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	1,334,307	$0.35196	469,623		1,334,307	$0.36595	488,285	
Off-Peak	12,507,735	$0.13241	1,656,149		12,507,735	$0.13729	1,717,131	
Winter								
Part-Peak	2,023,595	$0.13859	280,450		2,023,595	$0.14351	290,406	
Off-Peak	3,222,364	$0.11542	371,925		3,222,364	$0.11896	383,328	
Revenue from Energy Charges			2,778,147				2,879,150	
Revenue from Energy as % of Total			66.66%				68.06%	
CUSTOMER CHARGE ($/meter/mo.)				($/meter/day)				($/meter/day)
Ag VA	21,816	$14.40	314,150	.47310	21,816	$17.30	377,417	.56838
Revenue from Customer Charges			314,150				377,417	
Revenue from Customer Chrg as % of Total			7.54%				8.92%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	21,816	$6.80	148,349	.22341	21,816	$0.00	0	.00000
Revenue from Meter Charges			148,349				0	
Revenue from Meter Chrg as % of Total			3.56%				0.00%	
			4,167,735	Total Rev			4,230,011	Total Rev
							1.5%	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

AG 4A	JANUARY 1, 2011 RATES: Bundled Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT: Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	1,060,285	$4.83	5,121,176		1,060,285	$5.07	5,377,234	
Winter								
Maximum	1,060,289	$0.71	752,805		1,060,289	$0.75	790,445	
Revenue from Demand Charges			5,873,980				6,167,680	
Revenue from Demand as % of Total			22.70%				23.48%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	9,748,544	$0.28793	2,806,898		9,748,544	$0.30051	2,929,565	
Off-Peak	78,934,147	$0.13341	10,530,605		78,934,147	$0.13804	10,895,771	
Winter								
Part-Peak	10,797,868	$0.13800	1,490,106		10,797,868	$0.14278	1,541,701	
Off-Peak	20,567,414	$0.11510	2,367,309		20,567,414	$0.11854	2,438,140	
Revenue from Energy Charges			17,194,918				17,805,177	
Revenue from Energy as % of Total			66.44%				67.78%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	132,672	$14.40	1,910,477	.47310	132,672	$17.30	2,295,226	.56838
Revenue from Customer Charges			1,910,477				2,295,226	
Revenue from Customer Chrg as % of Total			7.38%				8.74%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	132,672	$6.80	902,170	.22341	132,672	$0.00	0	.00000
Revenue from Meter Charges			902,170				0	
Revenue from Meter Chrg as % of Total			3.49%				0.00%	
			25,881,545	Total Rev			26,268,082	Total Rev
							1.5%	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 5A	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/hp of connected load)								
Summer								
Maximum	269,390	$7.94	2,138,959		269,390	$8.34	2,245,907	
Winter								
Maximum	269,123	$1.43	384,846		269,123	$1.50	404,089	
Revenue from Demand Charges			2,523,806				2,649,996	
Revenue from Demand as % of Total			19.63%				20.31%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	8,801,024	$0.22220	1,955,588		8,801,024	$0.22889	2,014,430	
Off-Peak	41,806,314	$0.11662	4,875,452		41,806,314	$0.11908	4,978,400	
Winter								
Part-Peak	9,428,195	$0.12239	1,153,917		9,428,195	$0.12514	1,179,804	
Off-Peak	14,634,174	$0.10470	1,532,198		14,634,174	$0.10663	1,560,441	
Revenue from Energy Charges			9,517,155				9,733,074	
Revenue from Energy as % of Total			74.02%				74.59%	
CUSTOMER CHARGE ($/meter/mo.)	38,507	$14.40	554,497	($/meter/day) .47310	38,507	$17.30	666,166	($/meter/day) .56838
Revenue from Customer Charges			554,497				666,166	
Revenue from Customer Chrg as % of Total			4.31%				5.11%	
METER CHARGE ($/meter/mo.)	38,507	$6.80	261,846	($/meter/day) .22341	38,507	$0.00	0	($/meter/day) .00000
Revenue from Meter Charges			261,846				0	
Revenue from Meter Chrg as % of Total			2.04%				0.00%	
			12,857,302	Total Rev			13,049,236	Total Rev
							1.5%	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 1B	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Maximum	1,513,812	$8.15	12,337,572		1,513,812	$8.56	12,954,450	
Winter								
Maximum	1,098,934	$1.64	1,802,252		1,098,934	$1.72	1,892,364	
Revenue from Demand Charges			14,139,824				14,846,815	
Revenue from Demand as % of Total			22.52%				23.30%	
ENERGY CHARGE ($/kWh)								
Summer	194,016,342	$0.18140	35,194,564		194,016,342	$0.18113	35,142,225	
Winter	80,905,931	$0.14320	11,585,729		80,905,931	$0.14214	11,500,314	
Revenue from Energy Charges			46,780,294				46,642,539	
Revenue from Energy as % of Total			74.52%				73.20%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	96,772	$19.20	1,858,023	.63080	96,772	$23.00	2,225,756	.75565
Revenue from Customer Charges			1,858,023				2,225,756	
Revenue from Customer Chrg as % of Total			2.96%				3.49%	
			62,778,140	Total Rev			63,715,111	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($0.88)				($0.92)		
Winter		($0.22)				($0.23)		

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG RB	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	67,165	$2.63	176,643		67,165	$2.76	185,475	
Maximum	170,149	$6.72	1,143,405		170,149	$7.06	1,200,575	
Winter								
Maximum	113,164	$1.35	152,772		113,164	$1.42	160,411	
Revenue from Demand Charges			1,472,820				1,546,461	
Revenue from Demand as % of Total			26.89%				27.82%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	931,860	$0.35633	332,050		931,860	$0.35796	333,565	
Off-Peak	20,033,514	$0.13118	2,627,996		20,033,514	$0.13227	2,649,856	
Winter								
Part-Peak	2,678,140	$0.12337	330,402		2,678,140	$0.12442	333,218	
Off-Peak	4,457,412	$0.10457	466,112		4,457,412	$0.10536	469,625	
Revenue from Energy Charges			3,756,560				3,786,263	
Revenue from Energy as % of Total			68.60%	($/meter/day)			68.13%	($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	9,780	$19.20	187,776	.63080	9,780	$23.00	224,940	.75565
Revenue from Customer Charges			187,776				224,940	
Revenue from Customer Chrg as % of Total			3.43%				4.05%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	9,780	$6.00	58,680	.19713	9,780	$0.00	0	.00000
Revenue from Meter Charges			58,680				0	
Revenue from Meter Chrg as % of Total			1.07%				0.00%	
			5,475,694	Total Rev			5,557,515	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	200	($0.58)	(116)		200	($0.61)	(122)	
Winter	122	($0.21)	(26)		122	($0.22)	(27)	

Pacific Gas and Electric Company
2011 GRC Rate Design Changes - Exhibit A

	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG VB	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	47,539	$2.61	124,076		47,539	$2.74	130,280	
Maximum	83,210	$6.76	562,497		83,210	$7.10	590,622	
Winter								
Maximum	59,434	$1.33	79,048		59,434	$1.40	83,000	
Revenue from Demand Charges			765,621				803,902	
Revenue from Demand as % of Total			27.89%				28.85%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	668,823	$0.32838	219,628		668,823	$0.33003	220,730	
Off-Peak	9,412,573	$0.12784	1,203,303		9,412,573	$0.12888	1,213,116	
Winter								
Part-Peak	1,646,642	$0.12192	200,759		1,646,642	$0.12291	202,382	
Off-Peak	2,185,100	$0.10334	225,808		2,185,100	$0.10408	227,419	
Revenue from Energy Charges			1,849,498				1,863,648	
Revenue from Energy as % of Total			67.37%				66.88%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	5,172	$19.20	99,302	.63080	5,172	$23.00	118,956	.75565
Revenue from Customer Charges			99,302				118,956	
Revenue from Customer Chrg as % of Total			3.62%				4.27%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	5,172	$6.00	31,032	.19713	5,172	$0.00	0	.00000
Revenue from Meter Charges			31,032				0	
Revenue from Meter Chrg as % of Total			1.13%				0.00%	
			2,745,454	Total Rev			2,786,506	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer		($0.63)				($0.66)		
Winter		($0.20)				($0.21)		

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AG 4B	JANUARY 1, 2011 RATES: Bundled Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT: Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	1,306,719	$3.53	4,612,718		1,306,719	$3.71	4,843,354	
Maximum	1,731,924	$6.48	11,222,870		1,731,924	$6.80	11,784,013	
Winter								
Maximum	1,213,851	$1.46	1,772,223		1,213,851	$1.53	1,860,834	
Revenue from Demand Charges			17,607,811				18,488,201	
Revenue from Demand as % of Total			28.57%				29.56%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	37,082,225	$0.21112	7,828,799		37,082,225	$0.21276	7,889,795	
Off-Peak	204,716,005	$0.11797	24,150,347		204,716,005	$0.11857	24,272,763	
Winter								
Part-Peak	37,886,280	$0.11796	4,469,066		37,886,280	$0.11862	4,494,215	
Off-Peak	52,898,899	$0.10063	5,323,216		52,898,899	$0.10113	5,349,512	
Revenue from Energy Charges			41,771,428				42,006,285	
Revenue from Energy as % of Total			67.78%				67.16%	
CUSTOMER CHARGE ($/meter/mo.)	89,424	$19.20	1,716,941	($/meter/day) .63080	89,424	$23.00	2,056,752	($/meter/day) .75565
Revenue from Customer Charges			1,716,941				2,056,752	
Revenue from Customer Chrg as % of Total			2.79%				3.29%	
METER CHARGE ($/meter/mo.)	89,424	$6.00	536,544	($/meter/day) .19713	89,424	$0.00	0	($/meter/day) .00000
Revenue from Meter Charges			536,544				0	
Revenue from Meter Chrg as % of Total			0.87%				0.00%	
			61,631,867	Total Rev			62,550,339	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	1,020	($0.72)	(735)		1,020	($0.76)	(771)	
Winter	533	($0.23)	(123)		533	($0.24)	(129)	

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AG 5B / E-37	JANUARY 1, 2011 RATES: Bundled Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT: Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	6,066,686	$7.08	42,952,134		6,066,686	$7.31	44,348,078	
Maximum	7,112,774	$10.91	77,600,370		7,112,774	$11.26	80,122,382	
Winter								
Maximum	5,820,570	$4.18	24,329,983		5,820,570	$4.32	25,120,708	
Revenue from Demand Charges			144,882,487				149,591,168	
Revenue from Demand as % of Total			32.74%				33.32%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	370,116,390	$0.16341	60,480,719		370,116,390	$0.16391	60,666,187	
Off-Peak	1,629,324,180	$0.07087	115,470,205		1,629,324,180	$0.07141	116,344,389	
Winter								
Part-Peak	495,377,823	$0.08632	42,761,014		495,377,823	$0.08686	43,026,799	
Off-Peak	753,387,744	$0.06448	48,578,442		753,387,744	$0.06502	48,982,658	
Revenue from Energy Charges			267,290,379				269,020,033	
Revenue from Energy as % of Total			65.95%				65.40%	
CUSTOMER CHARGE ($/meter/mo.)	146,631	$30.00	4,398,939	($/meter/day) .98563	146,631	$36.00	5,278,727	($/meter/day) 1.18275
Revenue from Customer Charges			4,398,939				5,278,727	
Revenue from Customer Chrg as % of Total			1.09%				1.28%	
METER CHARGE ($/meter/mo.)	146,631	$6.00	879,788	($/meter/day) .19713	146,631	$0.00	0	($/meter/day) .00000
Revenue from Meter Charges			879,788				0	
Revenue from Meter Chrg as % of Total			0.22%				0.00%	
E-BIP Discounts			($630,080)				($630,080)	
			405,275,550	Total Rev			411,338,641	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	744,863	($1.24)	(923,631)		744,863	($1.28)	(953,649)	
Winter	695,495	($0.14)	(97,369)		695,495	($0.14)	(100,534)	
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)								
Summer	927,769	($8.14)	(7,552,042)		927,769	($8.40)	(7,797,483)	
Winter	825,812	($3.60)	(2,972,922)		825,812	($3.72)	(3,069,542)	

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AG 4C	JANUARY 1, 2011 RATES: Bundled Billing Determinants	Total Rate	Revenue		ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT: Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	134,543	$8.35	1,123,436		134,543	$8.77	1,179,607	
Part-Peak	205,775	$1.59	327,182		205,775	$1.67	343,541	
Maximum	295,048	$3.29	970,709		295,048	$3.45	1,019,245	
Winter								
Part-Peak	205,952	$0.36	74,143		205,952	$0.38	77,850	
Maximum	302,467	$1.60	483,947		302,467	$1.68	508,144	
Revenue from Demand Charges			2,979,417				3,128,388	
Revenue from Demand as % of Total			31.43%				32.52%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	4,705,128	$0.19233	904,937		4,705,128	$0.19805	931,829	
Part Peak	6,492,199	$0.11678	758,159		6,492,199	$0.11917	773,663	
Off-Peak	23,632,115	$0.09021	2,131,853		23,632,115	$0.09151	2,162,685	
Winter								
Part-Peak	5,827,324	$0.09874	575,390		5,827,324	$0.10050	585,618	
Off-Peak	10,361,892	$0.08699	901,381		10,361,892	$0.08823	914,245	
Revenue from Energy Charges			5,271,720				5,368,040	
Revenue from Energy as % of Total			55.61%				55.80%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	17,348	$64.80	1,124,177	2.12895	17,348	$64.80	1,124,177	2.12895
Revenue from Customer Charges			1,124,177				1,124,177	
Revenue from Customer Chrg as % of Total			11.86%				11.69%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	17,348	$6.00	104,091	.19713	17,348	$0.00	0	.00000
Revenue from Meter Charges			104,091				0	
Revenue from Meter Chrg as % of Total			1.10%				0.00%	
			9,479,405	Total Rev			9,620,605	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW)								
Summer On Peak		($0.94)				($0.99)		
Winter Maximum		($0.20)				($0.21)		
TRANSMISSION VOLTAGE DISCOUNT ($/kW)								
Summer On Peak		($5.65)				($4.48)		
Summer Part Peak		N/A				($0.90)		
Summer Maximum		N/A				($0.16)		
Winter Part Peak		N/A				($0.38)		
Winter Maximum		($1.49)				($1.18)		

Pacific Gas and Electric Company
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	JANUARY 1, 2011 RATES				ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT			
AG 5C	Bundled Billing Determinants	Total Rate	Revenue		Billing Determinants	Total Rate	Revenue	
DEMAND CHARGE ($/kW)								
Summer								
Peak	1,317,689	$11.84	15,601,440		1,317,689	$12.30	16,212,993	
Part-Peak	1,541,938	$2.46	3,793,166		1,541,938	$2.55	3,935,873	
Maximum	1,680,816	$4.69	7,883,028		1,680,816	$4.79	8,051,352	
Winter								
Part-Peak	1,268,259	$0.61	773,638		1,268,259	$0.62	789,885	
Maximum	1,342,313	$3.13	4,201,440		1,342,313	$3.20	4,291,891	
Revenue from Demand Charges			32,252,713				33,281,993	
Revenue from Demand as % of Total			34.21%				34.87%	
ENERGY CHARGE ($/kWh)								
Summer								
Peak	82,730,057	$0.11988	9,917,679		82,730,057	$0.12043	9,963,235	
Part-Peak	102,551,406	$0.08334	8,546,634		102,551,406	$0.08388	8,602,445	
Off-Peak	290,550,775	$0.06972	20,257,200		290,550,775	$0.07026	20,414,629	
Winter								
Part-Peak	106,213,762	$0.07381	7,839,638		106,213,762	$0.07435	7,897,264	
Off-Peak	153,276,098	$0.06761	10,362,997		153,276,098	$0.06815	10,445,990	
Revenue from Energy Charges			56,924,148				57,323,563	
Revenue from Energy as % of Total			62.35%				61.86%	
				($/meter/day)				($/meter/day)
CUSTOMER CHARGE ($/meter/mo.)	18,939	$160.00	3,030,308	5.25667	18,939	$160.00	3,030,308	5.25667
Revenue from Customer Charges			3,030,308				3,030,308	
Revenue from Customer Chrg as % of Total			3.32%				3.27%	
				($/meter/day)				($/meter/day)
METER CHARGE ($/meter/mo.)	18,939	$6.00	113,637	.19713	18,939	$0.00	0	.00000
Revenue from Meter Charges			113,637				0	
Revenue from Meter Chrg as % of Total			0.12%				0.00%	
E-BIP Discount			(131,400)				(131,400)	
			91,303,873	Total Rev			92,667,963	Total Rev
							1.5%	
PRIMARY VOLTAGE DISCOUNT ($/kW)								
Summer On Peak	119,279	($1.77)	(211,124)		106,370	($1.85)	(196,917)	
Winter Maximum	91,252	($0.17)	(15,513)		91,252	($0.17)	(15,839)	
TRANSMISSION VOLTAGE DISCOUNT ($/kW)								
Summer On Peak	56,696	($10.96)	(621,388)		51,448	($7.54)	(388,138)	
Summer Part Peak		N/A			55,898	($1.10)	(61,305)	
Summer Maximum		N/A			56,696	($2.40)	(136,006)	
Winter Part Peak		N/A			15,825	($0.62)	(9,856)	
Winter Maximum	16,451	($2.28)	(37,508)		16,451	($1.73)	(28,440)	

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ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT

AG 1A	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/hp of connected load)					
Summer	4.57	1.10	.00	.00	5.67
Winter	1.07	.00	.00	.00	1.07
ENERGY CHARGE ($/kWh)					
Summer	.08622	.07166	.02250	.02699	.20736
Winter	.05747	.05618	.02250	.02699	.16314
CUSTOMER CHARGE ($/meter/day)	.56838	.00000	.00000	.00000	.56838

AG RA	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/hp of connected load)					
Summer	4.03	1.05	.00	.00	5.08
Winter	.82	.00	.00	.00	.82
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.15376	.19301	.01808	.02699	.39183
Off-Peak	.05125	.04368	.01808	.02699	.14000
Winter					
Part-Peak	.04871	.04899	.01808	.02699	.14277
Off-Peak	.03246	.04073	.01808	.02699	.11826
CUSTOMER CHARGE ($/meter/day)	.56838	.00000	.00000	.00000	.56838

AG VA	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/hp of connected load)					
Summer	4.00	1.10	.00	.00	5.10
Winter	.85	.00	.00	.00	.85
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.14594	.17490	.01812	.02699	.36595
Off-Peak	.04864	.04354	.01812	.02699	.13729
Winter					
Part-Peak	.04841	.05000	.01812	.02699	.14351
Off-Peak	.03227	.04158	.01812	.02699	.11896
CUSTOMER CHARGE ($/meter/day)	.56838	.00000	.00000	.00000	.56838

AG 4A	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/hp of connected load)					
Summer	3.98	1.09	.00	.00	5.07
Winter	.75	.00	.00	.00	.75
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.13767	.11782	.01804	.02699	.30051
Off-Peak	.04588	.04713	.01804	.02699	.13804
Winter					
Part-Peak	.04741	.05034	.01804	.02699	.14278
Off-Peak	.03161	.04191	.01804	.02699	.11854
CUSTOMER CHARGE ($/meter/day)	.56838	.00000	.00000	.00000	.56838

AG 5A	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/hp of connected load)					
Summer	5.45	2.89	.00	.00	8.34
Winter	1.50	.00	.00	.00	1.50
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.07768	.10817	.01605	.02699	.22889
Off-Peak	.02590	.05015	.01605	.02699	.11908
Winter					
Part-Peak	.02926	.05284	.01605	.02699	.12514
Off-Peak	.01949	.04410	.01605	.02699	.10663
CUSTOMER CHARGE ($/meter/day)	.56838	.00000	.00000	.00000	.56838

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ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT

	Distr	Gen	PPP	Other	Total
AG 1B					
DEMAND CHARGE ($/kW)					
Summer	6.91	1.65	.00	.00	8.56
Winter	1.72	.00	.00	.00	1.72
ENERGY CHARGE ($/kWh)					
Summer	.06830	.06747	.01837	.02699	.18113
Winter	.04555	.05124	.01837	.02699	.14214
CUSTOMER CHARGE ($/meter/day)	.75565	.00000	.00000	.00000	.75565
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.34)	(.59)	.00	.00	(.92)
Winter	(.23)	.00	.00	.00	(.23)

	Distr	Gen	PPP	Other	Total
AG RB					
DEMAND CHARGE ($/kW)					
Summer					
Peak	1.09	1.67	.00	.00	2.76
Maximum	5.49	1.56	.00	.00	7.06
Winter					
Maximum	1.42	.00	.00	.00	1.42
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.10853	.20543	.01701	.02699	.35796
Off-Peak	.03617	.05211	.01701	.02699	.13227
Winter					
Part-Peak	.03317	.04726	.01701	.02699	.12442
Off-Peak	.02209	.03927	.01701	.02699	.10536
CUSTOMER CHARGE ($/meter/day)	.75565	.00000	.00000	.00000	.75565
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.24)	(.37)	.00	.00	(.61)
Winter	(.22)	.00	.00	.00	(.22)

	Distr	Gen	PPP	Other	Total
AG VB					
DEMAND CHARGE ($/kW)					
Summer					
Peak	.99	1.75	.00	.00	2.74
Maximum	5.66	1.44	.00	.00	7.10
Winter					
Maximum	1.40	.00	.00	.00	1.40
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.10791	.17827	.01686	.02699	.33003
Off-Peak	.03598	.04906	.01686	.02699	.12888
Winter					
Part-Peak	.03298	.04608	.01686	.02699	.12291
Off-Peak	.02197	.03826	.01686	.02699	.10408
CUSTOMER CHARGE ($/meter/day)	.75565	.00000	.00000	.00000	.75565
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.26)	(.40)	.00	.00	(.66)
Winter	(.21)	.00	.00	.00	(.21)

	Distr	Gen	PPP	Other	Total
AG 4B					
DEMAND CHARGE ($/kW)					
Summer					
Peak	1.76	1.94	.00	.00	3.71
Maximum	4.92	1.88	.00	.00	6.80
Winter					
Maximum	1.53	.00	.00	.00	1.53
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.08239	.08700	.01639	.02699	.21276
Off-Peak	.02746	.04774	.01639	.02699	.11857
Winter					
Part-Peak	.02887	.04638	.01639	.02699	.11862
Off-Peak	.01925	.03850	.01639	.02699	.10113
CUSTOMER CHARGE ($/meter/day)	.75565	.00000	.00000	.00000	.75565
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.30)	(.45)	.00	.00	(.76)
Winter	(.24)	.00	.00	.00	(.24)

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ILLUSTRATIVE RATES FOR
AG RATE DESIGN SETTLEMENT

AG 5B / E-37	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/kW)					
Summer					
Peak	3.05	4.26	.00	.00	7.31
Maximum	7.79	3.48	.00	.00	11.26
Winter					
Maximum	4.32	.00	.00	.00	4.32
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.00842	.11507	.01343	.02699	.16391
Off-Peak	.00000	.03099	.01343	.02699	.07141
Winter					
Part-Peak	.00000	.04644	.01343	.02699	.08686
Off-Peak	.00000	.02460	.01343	.02699	.06502
CUSTOMER CHARGE ($/meter/day)	1.18275	.00000	.00000	.00000	1.18275
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(.22)	(1.06)	.00	.00	(1.28)
Winter	(.14)	.00	.00	.00	(.14)
TRANSMISSION VOLTAGE DISCOUNT ($/kW of maximum demand)					
Summer	(6.47)	(1.93)	.00	.00	(8.40)
Winter	(3.72)	.00	.00	.00	(3.72)

AG 4C	Distr	Gen	PPP	Other	Total
DEMAND CHARGE ($/kW)					
Summer					
Peak	4.27	4.49	.00	.00	8.77
Part-Peak	.90	.77	.00	.00	1.67
Maximum	3.45	.00	.00	.00	3.45
Winter					
Part-Peak	.38	.00	.00	.00	.38
Maximum	1.68	.00	.00	.00	1.68
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.05382	.10076	.01648	.02699	.19805
Part Peak	.02151	.05419	.01648	.02699	.11917
Off-Peak	.01077	.03727	.01648	.02699	.09151
Winter					
Part-Peak	.01496	.04207	.01648	.02699	.10050
Off-Peak	.00996	.03480	.01648	.02699	.08823
CUSTOMER CHARGE ($/meter/day)	2.12895	.00000	.00000	.00000	2.12895
PRIMARY VOLTAGE DISCOUNT ($/kW)					
Summer On Peak	(.22)	(.77)	.00	.00	(.99)
Winter Maximum	(.21)	.00	.00	.00	(.21)
TRANSMISSION VOLTAGE DISCOUNT ($/kW)					
Summer On Peak	($3.02)	($1.46)	$0.00	.00	($4.48)
Summer Part Peak	($0.90)	$0.00	$0.00	.00	($0.90)
Summer Maximum	($0.16)	$0.00	$0.00	.00	($0.16)
Winter Part Peak	($0.38)	$0.00	$0.00	.00	($0.38)
Winter Maximum	($1.18)	$0.00	$0.00	.00	($1.18)

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	ILLUSTRATIVE RATES FOR AG RATE DESIGN SETTLEMENT				
	Distr	Gen	PPP	Other	Total
AG 5C					
DEMAND CHARGE ($/kW)					
Summer					
Peak	4.50	7.80	.00	.00	12.30
Part-Peak	1.07	1.48	.00	.00	2.55
Maximum	4.79	.00	.00	.00	4.79
Winter					
Part-Peak	.62	.00	.00	.00	.62
Maximum	3.20	.00	.00	.00	3.20
ENERGY CHARGE ($/kWh)					
Summer					
Peak	.00000	.08026	.01318	.02699	.12043
Part-Peak	.00000	.04372	.01318	.02699	.08388
Off-Peak	.00000	.03010	.01318	.02699	.07026
Winter					
Part-Peak	.00000	.03419	.01318	.02699	.07435
Off-Peak	.00000	.02798	.01318	.02699	.06815
CUSTOMER CHARGE ($/meter/day)	5.25667	.00000	.00000	.00000	5.25667
PRIMARY VOLTAGE DISCOUNT ($/kW)					
Summer On Peak	(.26)	(1.60)	.00	.00	(1.85)
Winter Maximum	(.17)	.00	.00	.00	(.17)
TRANSMISSION VOLTAGE DISCOUNT ($/kW)					
Summer On Peak	($4.50)	($3.04)	.00	.00	($7.54)
Summer Part Peak	($1.07)	($0.02)	.00	.00	($1.10)
Summer Maximum	($2.40)	$0.00	.00	.00	($2.40)
Winter Part Peak	($0.62)	$0.00	.00	.00	($0.62)
Winter Maximum	($1.73)	$0.00	.00	.00	($1.73)

EXHIBIT B

Illustrative Revenue Neutrality Adjustments for AG-1A Customers Defaulting to AG-4A and for AG-1B Customers Defaulting to AG-4B

Illustrative TOU Revenue Shortfall Adjustments for AG4A Group of Schedules (AG4A, AGRA, and AGVA)

Adjustment Cycle	Record Periods & Effective Dates		Customers Assigned to TOU		Billed Revenue Amounts		Shortfall Amounts		Savings Due to TOU Shifts	
	12 Months to	Rates Effective	Customers	kWh Used	AG1A	AG4A	Nominal	Adjusted	Summer	Winter
2014 AET	9/30/2013	1/1/2014	20,000	100,000,000	$28,000,000	$23,500,000	$4,500,000	**$4,177,500**	$300,000	$22,500
2015 AET	9/30/2014	1/1/2015	30,000	200,000,000	$56,000,000	$46,000,000	$10,000,000	**$9,095,000**	$840,000	$65,000

<u>Notes</u>:

1. TOU revenue shortfall adjustment amounts to be calculated based on 12-month record periods ending September 30, and applied to subsequent year AET rates
2. Record period for 2014 AET rates will start with March 1, 2013 implementation date for TOU; record period for 2015 AET rates will end with effective date of 2014 GRC Phase 2 rates
3. Customers and usage "assigned to TOU" are cumulative; they reflect record period usage of all prior-AG1A customers receiving service under an AG4A schedule during the record period
4. Billed revenue amounts will reflect record-period billing data for amounts billed under the AG4A schedules; AG1A-applicable revenue amounts to be calculated using record-period usage
5. Nominal revenue shortfall amounts reflect simple difference between AG1A versus AG4A revenue amounts; adjusted shortfall amounts are net of savings attributal to TOU usage shifts
6. Adjusted shortfall amounts to be applied as "non-allocated revenues" adjustment to AG4A group of rate schedules when AET rates are filed

Adjustment Cycle	Original Peak TOU Shares		Actual Peak TOU Shares		Seasonal kWh		kWh Shifted to Off-Peak		Off-Peak TOU Savings	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2014 AET	20.5%	42.5%	18.0%	38.0%	80,000,000	20,000,000	2,000,000	900,000	$0.15000	$0.02500
2015 AET	20.5%	42.5%	17.0%	36.0%	160,000,000	40,000,000	5,600,000	2,600,000	$0.15000	$0.02500

<u>Notes</u>:

1. Original peak-period TOU usage shares will be based on TOU usage data for migrating AG1A customers in last 12 billing cyles prior to their assignment to their new TOU rate
2. Actual TOU shares and summer versus-winter billed kWh will reflect record period usage of all prior-AG1A customers receiving service under an AG4A schedule during the record period
3. Summer and winter usage shifted to off-peak TOU periods is calculated by multiplying difference between "original" and "actual" TOU shares by record-period summer and winter kWh
4. Off-peak TOU savings are illustrative and will reflect average difference between on-peak and off-peak TOU rates for AG4A schedules (weighted by loads of the new TOU customers)

Illustrative TOU Revenue Shortfall Adjustments for AG4B Group of Schedules (AG4B, AGRB, and AGVB)

Adjustment Cycle	Record Periods & Effective Dates: 12 Months to	Record Periods & Effective Dates: Rates Effective	Customers Assigned to TOU: Customers	Customers Assigned to TOU: kWh Used	Billed Revenue Amounts: AG1B	Billed Revenue Amounts: AG4B	Shortfall Amounts: Nominal	Shortfall Amounts: Adjusted	Savings Due to TOU Shifts: On-Peak kW	Savings Due to TOU Shifts: Summer kWh	Savings Due to TOU Shifts: Winter kWh
2014 AET	9/30/2013	1/1/2014	4,000	125,000,000	$28,750,000	$24,750,000	$4,000,000	**$3,468,007**	$69,493	$450,000	$12,500
2015 AET	9/30/2014	1/1/2015	8,000	250,000,000	$57,500,000	$48,750,000	$8,750,000	**$7,273,338**	$226,662	$1,200,000	$50,000

Notes:
1. TOU revenue shortfall adjustment amounts to be calculated based on 12-month record periods ending September 30, and applied to subsequent year AET rates
2. Record period for 2014 AET rates will start with March 1, 2013 implementation date for TOU; record period for 2015 AET rates will end with effective date of 2014 GRC Phase 2 rates
3. Customers and usage "assigned to TOU" are cumulative; they reflect record period usage of all prior-AG1B customers receiving service under an AG4B schedule during the record period
4. Billed revenue amounts will reflect record-period billing data for amounts billed under the AG4B schedules; AG1B-applicable revenue amounts to be calculated using record-period usage
5. Nominal revenue shortfall amounts reflect simple difference between AG1B versus AG4B revenue amounts; adjusted shortfalls are net of savings attributable to TOU demand and energy usage shifts
6. Adjusted shortfall amounts to be applied as "non-allocated revenues" adjustment to AG4B group of rate schedules when AET rates are filed

1. TOU Period Usage Changes

Adjustment Cycle	Original Peak TOU Shares: Summer	Original Peak TOU Shares: Winter	Actual Peak TOU Shares: Summer	Actual Peak TOU Shares: Winter	Seasonal kWh: Summer	Seasonal kWh: Winter	kWh Shifted to Off-Peak: Summer	kWh Shifted to Off-Peak: Winter	Off-Peak TOU Savings: Summer	Off-Peak TOU Savings: Winter
2014 AET	23.0%	47.0%	20.0%	45.0%	100,000,000	25,000,000	3,000,000	500,000	$0.15000	$0.02500
2015 AET	23.0%	47.0%	19.0%	43.0%	200,000,000	50,000,000	8,000,000	2,000,000	$0.15000	$0.02500

Notes:
1. Original peak-period TOU usage shares will be based on TOU usage data for migrating AG1B customers in last 12 billing cyles prior to their assignment to their new TOU rate
2. Actual TOU shares and summer versus-winter billed kWh will reflect record period usage of all prior-AG1B customers receiving service under an AG4B schedule during the record period
3. Summer and winter usage shifted to off-peak TOU periods is calculated by multiplying difference between "original" and "actual" TOU shares by record-period summer and winter kWh
4. Off-peak TOU savings are illustrative and will reflect average difference between on-peak and off-peak TOU rates for AG4B schedules (weighted by loads of the new TOU customers)

2. TOU Demand Changes

Adjustment Cycle	Original kWh/On-Pk kW: Summer	Original kWh/On-Pk kW: Winter	Actual kWh/On-Pk kW: Summer	Actual kWh/On-Pk kW: Winter	Summer On-Peak kW: Original	Summer On-Peak kW: Actual	Reduced On-Peak kW: Summer	Reduced On-Peak kW: Winter	On-Peak Demand Savings: Rate	On-Peak Demand Savings: Amount
2014 AET	176	N/A	182	N/A	568,182	549,451	18,731	N/A	$3.71	$69,493
2015 AET	176	N/A	186	N/A	1,136,364	1,075,269	61,095	N/A	$3.71	$226,662

Notes:
1. Original kWh/On-Pk kW ratio will be based on TOU demand and energy usage data for migrating AG1B customers in last 12 billing cyles prior to their assignment to their new TOU rate
2. Original kWh/On-Pk kW ratio will be calculated as ratio of total summer-season billed kWh divided by total summer-season on-peak demand (kW)
3. Actual kWh/On-Pk kW ratio will reflect record period usage of all prior-AG1B customers receiving service under an AG4B schedule during the record period
4. Reduced summer on-peak demand is calculated as difference between demand derived from "original" demand ratio and actual billed summer on-peak demand during the record period
5. On-Peak Demand Charge savings will be calculated by multiplying inferred on-peak demand reductions (kW) by applicable demand charge ($/kW)

Exhibit B

Historic TOU Shares for AG4A and AG4B -- Calendar-Years 2006 - 2010

Default TOU Customers

Rate Group	Season	TOU Period	Calendar Year Annual Sales (MWH) 2006	2007	2008	2009	2010	Ag 1 Customers w/SmartMeters
AG4A	Summer	On-Peak	11,379	13,062	14,009	13,630	13,078	3,781
		Off-Peak	92,643	108,488	111,511	109,587	102,697	14,703
	Winter	Part-Peak	6,989	13,129	13,211	13,236	8,007	2,700
		Off-Peak	13,359	25,446	25,743	24,071	15,145	3,634
	Summer	Total	104,022	121,551	125,521	123,217	115,775	18,484
	Winter	Total	20,348	38,575	38,955	37,307	23,152	6,335
	Annual	Total	124,370	160,126	164,475	160,524	138,928	24,819
AG4A	Summer	On-Peak	10.9%	10.7%	11.2%	11.1%	11.3%	20.5%
		Off-Peak	89.1%	89.3%	88.8%	88.9%	88.7%	79.5%
	Winter	Part-Peak	34.3%	34.0%	33.9%	35.5%	34.6%	42.6%
		Off-Peak	65.7%	66.0%	66.1%	64.5%	65.4%	57.4%
	Summer	Total	83.6%	75.9%	76.3%	76.8%	83.3%	74.5%
	Winter	Total	16.4%	24.1%	23.7%	23.2%	16.7%	25.5%
	Annual	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Rate Group	Season	TOU Period	Calendar Year Annual Sales (MWH) 2006	2007	2008	2009	2010	Ag 1 Customers w/SmartMeters
AG4B	Summer	On-Peak	40,507	50,452	50,604	52,530	48,049	869
		Off-Peak	228,395	278,279	281,011	282,961	257,364	2,893
	Winter	Part-Peak	29,750	48,835	45,916	47,578	30,586	696
		Off-Peak	40,595	67,668	64,364	65,535	41,328	792
	Summer	Total	268,902	328,732	331,615	335,491	305,413	3,763
	Winter	Total	70,345	116,503	110,280	113,114	71,914	1,488
	Annual	Total	339,247	445,235	441,895	448,605	377,327	5,251
AG4B	Summer	On-Peak	15.1%	15.3%	15.3%	15.7%	15.7%	23.1%
		Off-Peak	84.9%	84.7%	84.7%	84.3%	84.3%	76.9%
	Winter	Part-Peak	42.3%	41.9%	41.6%	42.1%	42.5%	46.8%
		Off-Peak	57.7%	58.1%	58.4%	57.9%	57.5%	53.2%
	Summer	Total	79.3%	73.8%	75.0%	74.8%	80.9%	71.7%
	Winter	Total	20.7%	26.2%	25.0%	25.2%	19.1%	28.3%
	Annual	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Historic TOU and Max Demand Relationships for AG4B Customer Population

Rate Group	Season	Type	Calendar Year Billing Demands (kW) 2006	2007	2008	2009	2010	Default TOU Customers: AG1 Customers w/SmartMeters
AG4B	Summer	On-Peak	1,316,979	1,450,830	1,524,178	1,606,958	1,567,168	21,344
	Summer	Maximum	1,787,519	1,928,897	1,998,705	2,090,072	2,039,315	23,068
	Winter	Maximum	1,041,793	1,337,353	1,266,372	1,340,202	1,171,346	15,809

Rate Group	Season	Type	Billed kWh per kW of Billed Demand 2006	2007	2008	2009	2010	AG1 Customers w/SmartMeters
AG4B	Summer	On-Peak	30.8	34.8	33.2	32.7	30.7	40.7
	Summer	Total Use	204.2	226.6	217.6	208.8	194.9	176.3
	Summer	Maximum	150.4	170.4	165.9	160.5	149.8	163.1
	Winter	Maximum	67.5	87.1	87.1	84.4	61.4	94.1

Notes:

Summer	On-Peak	=	Summer On-Peak Energy (kWh) divided by On-Peak Demand (kW)
Summer	Total Use	=	Summer Total Energy used (kWh) divided by On-Peak Demand (kW)
Summer	Maximum	=	Summer Total Energy used (kWh) divided by billed Max Demand (kW)
Winter	Maximum	=	Winter Total Energy used (kWh) divided by billed Max Demand (kW)

EXHIBIT C

Account Aggregation Study Framework and Supporting Documents

Exhibit C - Ag Settlement Agreement

Agricultural Account Aggregation Study Framework

The Settling Parties agree that it is reasonable not to adopt an agricultural account aggregation tariff in this proceeding. Instead, the Settling Parties agree to facilitate a Study to obtain data and other information on agricultural customers' electrical usage to allow evaluation of agricultural account aggregation.

1. Scope of Study. The Study framework and methodology below are agreed to by PG&E, AECA, CFBF, and SSJID. PG&E and Agricultural Consultants will work to reach agreement on the content of the report encompassing Parts A through D below. In general, these sections of the report should address the information and data gathered for the Study. For Part E, AECA, CFBF and SSJID will have responsibility to prepare the portion of the report addressing the analysis from the customer perspective, while PG&E will have responsibility to prepare the portion of the report addressing the analysis from the utility perspective.

A. As provided by the Agricultural Consultant Work Scope (copy attached), AECA, CFBF, and SSJID (through the Agricultural Consultants) will identify up to fifty potential participating customers and the data they determine will be necessary to select Study participants. As customers provide the necessary authorizations/releases in accordance with Part B, PG&E will provide the required data extract for the list of up to fifty potential participating customers. The Agricultural Consultants will identify up to fifteen farm operations, and between 5 and 15 individually metered accounts for each farm operation, with a goal of recruiting a diverse set of participants in terms of crop, animal husbandry (cattle/dairy/poultry), agricultural processes (e.g. cleaning, packing, hulling, ginning) and irrigation types, as well as the location of multiple accounts owned by a single agricultural customer on the same feeder, substation transformer bank, distribution planning area, or more geographically dispersed basis. The total number of accounts will be limited to no more than 150. PG&E will review the identified accounts to ensure that the necessary data will be available for the Study period. The Study period will be up to 12 months. The Study period of up to 12 months will be selected to commence the spring of 2012. PG&E will notify the Agricultural Consultants of any potential data availability issues so that replacement accounts may be selected as needed before the Study commences.

B. The Agricultural Consultants will be responsible for obtaining releases from participating customers pursuant to the Agricultural Consultant Work Scope. Participating customers with farm operations as noted in Part A must execute customer authorizations (copy attached) to release their usage data in a timely fashion in connection with the Study. Parties in the 2011 GRC Phase 2 or 2014 GRC Phase 2 proceeding, or other proceedings, who request to review the Study and underlying data, and who sign a non-disclosure agreement, will be provided access to the confidential portions of the Study and relevant Study data, without attributing the data to an identified customer. Individual customer names will not be disclosed, but locations may be identified by county or zip code, by latitude and longitude, and/or relative position on PG&E's grid, (as well as possibly information about the nature of the customer's electricity demands, the customer's agricultural activities associated with the meter, and information provided pursuant to the Agricultural Consultants' scope of work or Part D below).

C. PG&E will gather 15-minute interval data for the subject metered accounts for each participating customer for the period of the Study, and if available, for prior years. PG&E will determine the status quo billing determinants (i.e., those required under current rates and tariffs) and billing determinants if the metered accounts were aggregated, for a comparison analysis. In consultation with the Agricultural Consultants PG&E will determine the amount of the bills for each separately metered account and the amount of the bills taken on an aggregated basis. PG&E's aggregated bill calculations will be based on existing rates and will exclude any changes that might be proposed in future regulatory proceedings. The analysis will use appropriate simplifying assumptions. PG&E will make this analysis (including metered data) available to the Agricultural Consultants and other parties who have signed NDAs. This information will form the database for the analysis from the perspective of the participant.

D. Pursuant to the Agricultural Consultant Work Scope, the Agricultural Consultants may provide information and education to Study participants as a means to obtain data on farm operations and possible resulting changes in use patterns. Such activities will be fully documented and reported in the Study. No bill adjustments will be made to customers as a result of their participation in the Study or for any usage behaviors undertaken to augment the Study. The Agricultural Consultants shall not make any representations to Study participants or any other agricultural customers that this Study in any way assures that the CPUC or PG&E would, in the future, recommend or make changes to rates, programs, cost allocation or any other matters relating to the subject of the study.

E. AECA, CFBF and SSJID will have responsibility to prepare the portion of the report addressing the analysis from the customer perspective.

PG&E will analyze the Study data from the utility perspective, in addition to other information that PG&E deems necessary for analysis from the utility perspective (which information will be disclosed in the analysis, subject to standard confidentiality requirements), and include that analysis as part of the Study.

F. The analysis may also investigate whether allowing agricultural customers to aggregate multiple accounts serving separate loads on an individual agricultural customer's site would affect the customer's management of its load(s).

2. Agricultural Consultants Selected. The Agricultural Consultants shall be M.Cubed, and the subcontractors will include but not be limited to Aspen Environmental Group, Economic Insights and MRW & Associates.

3. Costs of the Study. Up to $250,000 (two hundred and fifty thousand), plus accrued interest, will be funded solely through agricultural customers' rates to facilitate the Study as outlined below:

1. Up to $150,000 of the $250,000 shall be used to pay incentives to customers who actually participate in the Study, with a payment equal to $10,000 per participant to help offset the cost of participating (participation payment). The initial $5,000 of the $10,000 participation payment will be paid to the participant once the Agricultural Consultants have selected the participant and associated accounts, and PG&E has confirmed that interval data will be available for the Study period. A second payment of $5,000 will be paid to the participant five months after the initial participation payment is paid, provided the participant has not withdrawn from the Study.
2. Up to $100,000 of the $250,000 shall be used to pay Agricultural Consultants for the work they will perform under the attached "Proposed Scope of Work for Agricultural Consultants" (Agricultural Consultant Work Scope).
3. PG&E shall not make participation payments to participants until the Commission has issued its final decision approving the 2011 GRC 2 Agricultural Settlement.
4. PG&E shall not remit payment to the Agricultural Consultants until the Commission has issued its final decision approving the 2011 GRC 2 Agricultural Settlement.

Amounts that PG&E pays to participants and Agricultural Consultants under the Agricultural Settlement, up to $250,000 plus accrued interest, shall be immediately recoverable in agricultural rates (excluding Schedule E-37) once the Study is made available in PG&E's 2014 GRC Phase 2. The Study costs, up to $250,000 plus accrued interest, will be recovered in agricultural customers' distribution rates via the Distribution Revenue Adjustment Mechanism and the Annual Electric True Up. This adjustment to agricultural rates will be in addition to any allocation separately established in other parts of this settlement or the related March 14, 2011 Settlement on Marginal Costs and Revenue Allocation. The Settling Parties shall support such recovery in all agricultural customers' rates by PG&E.

PG&E will provide its own staff and other resources, including information it deems necessary to undertake its study elements, which costs will not be recorded in the account accruing costs for the Study that will be recoverable from agricultural customers under the terms of the Agricultural Settlement. Other costs of participating in the Study, including all costs of advocacy for any particular position, will be borne by the individual participants and individual parties on their own account.

If the Commission does not approve the 2011 GRC 2 Agricultural Settlement all work on the Study shall cease and the Study shall not be done.

4. Results of Study Available To Participants for Use In Future CPUC Proceedings. The results will be available for parties to use in connection with revenue allocation and tariff design issues in the 2014 GRC Phase 2, or other proceedings, provided a final decision in the non-residential portion of the 2011 GRC Phase 2 proceeding is issued in a timely fashion to permit the Study to proceed.

5. Agreement To Participate In Study Does Not Resolve What Proposals The Parties Will Present, Support, or Oppose In Future Rate Cases. Whether or not to develop or present rate, program, cost allocation or other proposals in the 2014 GRC Phase 2 proceeding, or any other proceeding, however, is beyond the scope of the Study. Agreement to participate in this part of the Agricultural Settlement does not constitute support for the Study results and all parties reserve the right to litigate the merits of the Study results in any CPUC proceeding involving the Study.

6. The Study Will Not Be The Exclusive Source Of Information On Aggregation Issues That May Be Considered In Future Rate Cases. This analysis potentially may be used to litigate future agricultural rate design. Nothing in this Settlement precludes any party from presenting other data, information, analyses, expert opinion or other material on aggregation issues, or any other issues, in which the Study becomes involved.

In addition, Agricultural parties, PG&E and other interveners reserve all rights to file testimony on, comment on, question and otherwise test the Study in future proceedings, including without limitation, the participating customers, the data, analyses, conclusions, processes and methodologies, etc.

7. No Warranty That Rates To Customers Will Change As A Result of This Study. Participating customers and customers solicited to participate in the Study should understand that PG&E makes no representations regarding current or future rates, customer bill savings, customer benefits, programs, cost allocation or any other matters involving its provision of utility service in connection with the Study.

Appendix 1 to Exhibit C - Ag Settlement Agreement

Agricultural Settlement Aggregation Study
Proposed Scope of Work for Agricultural Consultants

Purpose of the Agricultural Settlement Aggregation Study:

The purpose of the Agricultural Settlement Aggregation Study (Study) is to obtain data and other information on a group of agricultural customers' electrical usage to allow evaluation of these agricultural customers' usage with account aggregation and what benefits, if any, might result from aggregating multiple accounts that serve separate loads located on the agricultural customer's farm operation. The Study may also investigate whether allowing agricultural customers to aggregate such multiple accounts would affect their management of their loads.

Whether or not to develop or present rate, program, cost allocation, or other proposals is beyond the scope of the Study. Participating customers and customers solicited to participate in the Study should understand that PG&E makes no representations regarding current or future rates, programs, customer bill savings, cost allocation or any other matters involving its provision of utility service in connection with the Study.

The effect on PG&E's system of the participating agricultural customers' electrical usage, such as for changes in their usage under the Study, is outside the scope of the work for the Agricultural Consultants. Analyses of the effect on PG&E's system shall be PG&E's responsibility.

The Study, and related information and data, will be available upon request to parties in PG&E's 2011 GRC 2 and 2014 GRC 2 proceedings, or in other proceedings where the Study is considered, once the requesting party has executed the non-disclosure agreement for the Study.

Nothing in the Agricultural Settlement prohibits the Agricultural Consultants from performing analyses outside the Study scope, in a separate role as consultants to parties in proceedings involving the Study, provided they use 1) their own resources and 2) customer specific data that is obtained under the Non-Disclosure Agreement for obtaining the Study and related data. Agricultural Consultants may not use information that they obtained *exclusively* in the performance of their responsibilities under the Agricultural Settlement to 1) perform work as consultants to parties, or 2) solicit or consult for customers or anyone else.

This document establishes the scope of work to be performed by the Agricultural Consultants by agreement with PG&E and as approved by the CPUC. An estimated budget is identified for each task. However, Agricultural Consultants may shift up to 20 percent of the total budget between tasks, with written notification to PG&E.

Agricultural Consultants: The Agricultural Consultants shall be M.Cubed, and the subcontractors to include but not be limited to Aspen Environmental Group, Economic Insights, and MRW & Associates.

Agricultural Consultants will execute the "Agreement Implementing Agricultural Settlement Aggregation Study" before starting any work on the study.

Task 1. Finalizing Study Parameters, Information Needs and Task Timing

Agricultural Consultants will work closely with PG&E to identify all final Study parameters, including but not limited to:

- Targeted timeframes
- Aggregation group definitions
- Farm operation characteristics
- Study group preferences

Targeted timeframe: TBD
Deliverables: final Study parameters

Budget: $5,000

Task 2. Recruiting Study Participants

Utilizing targeted outreach and working closely with agricultural customer representatives, Agricultural Consultants will identify up to 50 potential study participants. From this group of potential participants, the Agricultural Consultants will select a representative group of up to 15 agricultural customers to participate in the Study. The customer group should be designed to capture diversity for such factors as crops, animal husbandry (cattle/dairy/poultry), agricultural processes (e.g. cleaning, packing, hulling, ginning), irrigation types, and other appropriate characteristics such as contained in paragraph A of the Agricultural Settlement section on the Study.

Agricultural Consultants will obtain and provide to PG&E executed authorizations to release specific customer information in connection with the Study (copy attached). These releases/authorizations will permit potential participants' data to be shared with the Agricultural Consultants and will permit the participating customers' data to be shared in A.10-03-014 or PG&E's 2014 GRC 2 proceeding, or in other proceedings where the Study will be considered, with parties who execute the non-disclosure agreement for the Study and request the opportunity to review the Study and the data involved.

Upon receipt of the customers' executed authorizations and Commission approval of the Agricultural Settlement, PG&E will provide the potential participants' account and billing data to the Agricultural Consultants. Agricultural Consultants will undertake a careful analysis of the account and billing data to identify suitable agriculture customers to participate. PG&E will review the identified accounts to ensure that the necessary data will be available for the study period. Once the 15 final program participants are identified, Agricultural Consultants will undertake a thorough analysis of each participant's accounts and operational characteristics to identify the participants' 5 to 15 separately metered accounts that will be included in the Study. The Study shall be limited to 150 separately metered accounts. All selected separately metered accounts must be eligible for agricultural utility service. The Agricultural Consultants' analyses under this paragraph shall be provided to PG&E.

The confidential or proprietary data and information provided to Agricultural Consultants by PG&E and the Agricultural Consultants' analyses of specific customers under this Scope of Work may be used by the Agricultural Consultants only for purposes of the Study and proceedings involving the Study. The data, information, and the Agricultural Consultants' analyses of specific customers may be shared only with PG&E, the Commission staff under PUC § 583, and the qualified Reviewing Representatives for third parties who have executed the NDA for the Aggregation Study; provided, however, that the Agricultural Consultants may share with each individual customer specific data, information and analyses that are limited to that individual customer.

PG&E shall be allowed to attend any and all Study-related meetings between the Agricultural Consultants and Study participants. Agricultural Consultants will create and properly maintain an up-to-date meeting schedule accessible to PG&E, which PG&E can use to notify the Agricultural Consultants of meetings they would like to attend.

Targeted Timeframe: TBD
Agricultural Consultants' Deliverable(s): Documentation presenting and supporting consultants' analyses of all potential program participants' accounts and operational characteristics, including detailed information on semifinalists and the final 15 participants.

Budget: $40,000

Task 3. Participant Preparation and Education

Agricultural Consultants will work closely with participants to prepare them to engage in the Study. Farm operation characteristics influencing energy usage (e.g. water use patterns, irrigation practices, energy and irrigation infrastructure, crop types, animal husbandry, agricultural processes (e.g. cleaning, packing, hulling ginning) and labor requirements) will be compiled and reviewed to identify current operational characteristics and potential operational changes. Specific energy management practices might be recommended, and, if adopted, carefully examined to determine their outcomes and implications.

PG&E shall be allowed to attend any and all Study-related meetings between the Agricultural Consultants and Study participants. Agricultural Consultants will create and properly maintain an up-to-date meeting schedule accessible to PG&E, which PG&E can use to notify the Agricultural Consultants of meetings they would like to attend.

Agricultural Consultants shall provide PG&E in writing with (1) the information and recommendations that the Agricultural Consultants provide the participants and (2) complete descriptions of the activities the participants implement for the Study, and (3) the activities suggested to but rejected by the participants.

Targeted Timeframe: TBD
Deliverables: The material described in the preceding paragraph.

Budget: $20,000

Task 4. Ongoing Participant Support

Agricultural Consultants will be available to work with participants during the course of the Study as a resource to review energy management practices and answer questions.

PG&E shall be allowed to attend any and all Study-related meetings between the Agricultural Consultants and Study participants. Agricultural Consultants will create and properly maintain an up-to-date meeting schedule accessible to PG&E, which PG&E can use to notify the Agricultural Consultants of meetings they would like to attend.

Agricultural Consultants shall provide PG&E with complete written descriptions of the participants' questions and concerns, the energy management practices discussed with the participants, and Agricultural Consultants' answers.

Targeted Timeframe: TBD
Deliverables: Complete written descriptions and documentation of the participants' questions and concerns, energy management practices discussed with the participants, and Agricultural Consultants' answers.

Budget: $15,000

Task 5. Ongoing Study Review

Agricultural Consultants will meet with PG&E monthly, as necessary or upon PG&E's request, to review Study progress and review data and other information. Recommendations for adjustment to Study parameters will be presented and approved, if appropriate to ensure the accuracy and usefulness of the data being collected.

Budget: $10,000

Task 6. Study Conclusion Interviews

Upon completion of the study period, Agricultural Consultants will conduct exit interviews with Study participants about their energy use patterns, preferences, and experiences from the Study. The exit interviews shall be fully documented and provided to PG&E.

PG&E shall be allowed to attend any and all Study-related meetings between the Agricultural Consultants and Study participants. Agricultural Consultants will create and properly maintain an up-to-date meeting schedule accessible to PG&E, which PG&E can use to notify the Agricultural Consultants of meetings they would like to attend.

Targeted Timeframe: TBD
Deliverables: Complete, written reports of the exit interviews

Budget: $10,000

Cost
PG&E's agreed cost-sharing shall be limited to no more than $100,000 of ratepayer funds to come exclusively from agricultural customers.

M.Cubed shall be responsible to remit payments owed to the subcontractor consultants for their work on the study.

The estimated hourly rate for Agricultural Consultants is approximately $205 per hour.

Appendix 2 to Exhibit C - Ag Settlement

AUTHORIZATION TO RELEASE CUSTOMER INFORMATION IN CONNECTION WITH ACCOUNT AGGREGATION STUDY

The purpose of this agreement is to authorize the release of customer information for use in the Agricultural Settlement Account Aggregation Study (Study) contained in the Agricultural Settlement in the PG&E 2011 General Rate Case Phase 2 proceeding.

The release authorizes PG&E to release customer information under the terms of this authorization for purposes of selecting the customer participants in the Study. If the customer is not selected for participation in the Study, no additional release of customer information under this authorization will occur. If the customer is selected for the Study, additional release of customer information may occur in connection with the Study and regulatory proceedings (such as those conducted by the California Public Utilities Commission) involving the Study.

I, ______________________________(Name), ____________________(Title), of _______________________________________(Customer) have the following mailing address, ____and do hereby authorize Pacific Gas and Electric Company to release information for the following listed account(s) which are under consideration for or participating in the Study under the 2011 GRC 2 Agricultural Settlement in A.10-03-014:

Accounts included in this authorization:

1. ___________________________(service address), ________________(service account no.)
2. ___________________________(service address), ________________(service account no.)
3. ___________________________(service address), ________________(service account no.)
4. ___________________________(service address), ________________(service account no.)
5. ___________________________(service address), ________________(service account no.)
6. ___________________________(service address), ________________(service account no.)

7. ______________________________(service address), __________________(service account no.)
8. ______________________________(service address), __________________(service account no.)
9. ______________________________(service address), __________________(service account no.)
10. ______________________________(service address), __________________(service account no.)
11. ______________________________(service address), __________________(service account no.)
12. ______________________________(service address), __________________(service account no.)
13. ______________________________(service address), __________________(service account no.)
14. ______________________________(service address), __________________(service account no.)
15. ______________________________(service address), __________________(service account no.)
16. ______________________________(service address), __________________(service account no.)
17. ______________________________(service address), __________________(service account no.)
18. ______________________________(service address), __________________(service account no.)
19. ______________________________(service address), __________________(service account no.)
20. ______________________________(service address), __________________(service account no.)
23. ______________________________(service address), __________________(service account no.)
24. ______________________________(service address), __________________(service account no.)

Information, Acts and Functions authorized – This authorization provides authority to PG&E to provide information about the accounts included in this authorization in connection with the Study to the Agricultural Consultants identified in the 2011 GRC 2 Agricultural Settlement in the 2011 PG&E GRC 2 proceeding, and to parties in PG&E's 2011 GRC 2 or 2014 GRC 2 proceedings, or other regulatory proceeding in which the study and/or the underlying data are involved, who have signed a non-disclosure agreement. Agricultural Consultants may be provided with the customer's name and service address. Information disclosed under this authorization to other parties shall not contain the customer's name or service address, but may identify the location of each account by County or zip code, latitude and longitude, or relative position on PG&E's grid, and the customer's agricultural activity associated with each meter in the Study.

This authorization is only granted in connection with the Study, and proceedings involving the Study. Authorization is given for the period covered by the Study and until the Study is no longer used for regulatory or other advocacy purposes.

I (customer) __________________ understand that the purpose of the Study is obtain data and other information on a group of agricultural customers' electrical usage to allow evaluation of these agricultural customers' usage with account aggregation and what benefits, if any, may result from aggregating multiple accounts serving separate loads for an agricultural customer's farm operation. The Study may also investigate whether allowing farmers to aggregate such multiple accounts would affect their management of their loads. I understand that PG&E makes no representations regarding current or future rates, customer bill savings, customer benefits, programs, cost allocation or any other matters involving its provision of utility service that may arise in connection with the Study.

I (customer) _________________________________ (print name of authorized signatory), declare under penalty of perjury under the laws of the State of California that I am authorized to execute this document on behalf of the Customer of Record. I authorize PG&E to release the information on my account, facilities and/or operations as specified above. I hereby release, hold harmless, and indemnify PG&E from any liability, claims, demands, causes of action, damages, or expenses resulting from 1) any release of information pursuant to this Authorization, and 2) the unauthorized use of this information by other parties. I understand that this Authorization will remain in place, and cannot be terminated until completion of the Study and until the Study is no longer used for regulatory or other advocacy purposes.

_______________________________________ Authorized Customer Signature

____________________________ Telephone Number

Executed this _____ day of _________ ________
Month Year

at ____________________________
City and State where executed

Appendix 3 to Exhibit C - Ag Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design, including Real Time Pricing, to Revise its Customer Energy Statements, and to Seek Recovery of Incremental Expenditures (U 39 M) (caption to change depending on case involved)	Application 10-03-014 (filed March 22, 2010) (Caption to change depending on case involved)

NONDISCLOSURE AGREEMENT FOR AGRICULTURAL AGGREGATION STUDY UNDER THE AGRICULTURAL SETTLEMENT

This Nondisclosure Agreement ("Agreement") is effective this ____ day of ____, 20__, by and between Pacific Gas and Electric Company ("PG&E") and ____________________ on behalf of __________________________ ("Receiving Party").

RECITALS

A. Certain of the information requested to be produced or disclosed by PG&E, or by the Agricultural Consultants in the performance of the Proposed Scope of Work for Agricultural Consultants under the 2011 GRC 2 Agricultural Settlement constitutes confidential information, including but not limited to, customer specific data used for the Agricultural Account Aggregation Study ("Confidential Material").

B. PG&E and the Receiving Party believe that this Agreement will facilitate production of the Agricultural Account Aggregation Study ("Study") and Confidential Material in proceedings where the Study is involved.

C. PG&E and the Receiving Party believe that this Agreement will protect legitimate confidentiality concerns.

AGREEMENT

In consideration of the recitals set forth above, PG&E and the Receiving Party agree that the following terms and conditions shall govern the disclosure and use of the Study and Confidential Material in proceedings where the Study is involved.

1. For purposes of this Non-Disclosure Agreement (NDA):

a. The term "Confidential Material" includes data or information about customers which PG&E provided to the Agricultural Consultants for the purpose of performing the work under the Proposed Scope of Work for Agricultural Consultants, the Agricultural Consultants analyses of data, billing, farm operations, and other data regarding individual agricultural customers, data and analyses regarding other specific customers, and portions of the Study that PG&E determines to be confidential.

b. The term "notes of Confidential Material" means memoranda, handwritten notes, or any other form of information which copies, characterizes or discloses all or portions of Confidential Material.

c. The term "Reviewing Representative" is a person discussed in paragraphs 8 and 9 of this Agreement.

d. The term "Commission" means the California Public Utilities Commission.

2. The term of this NDA shall start from the effective date and continue through the periods for all Commission proceedings, both current and future, in which the Study may be involved (including without limitation, PG&E's 2014 GRC 2 proceeding). Expiration or termination of this NDA shall not abrogate the Receiving Party's obligations with respect to Confidential Material received prior to such expiration or termination. The obligations and terms of this NDA shall survive as long as the underlying legal basis (including, but not limited to, CPUC General Order 66-C and Commission decisions for maintaining the confidentiality of customer information) remain applicable and in effect.

3. Confidential Materials include memoranda, handwritten notes, spreadsheets, computer files and reports, and any other form of information (including information in electronic form) that copies, characterizes, discloses, or compiles other confidential Materials or from which such materials may be derived. (Nothing in this agreement prevents PG&E or another party from separately showing that any derivative materials are confidential.)

4. Confidential Materials shall be made available under the terms of this Agreement only to Reviewing Representatives as provided in paragraphs 8 and 9 of this Agreement.

5. Upon written request by PG&E at the end of a proceeding in which the Study has been involved, all Receiving Party and Reviewing Representatives shall return to PG&E within thirty (30) days all Confidential Material, including all copies of Confidential Material (except notes of Confidential Material). Within the time period for return of Confidential Material, the Receiving Party shall destroy all notes of Confidential Material and the Receiving Party shall submit to PG&E an affidavit stating that all confidential Material, copies thereof, and notes of Confidential Material are being returned to PG&E or have been destroyed in accordance with this paragraph. In the event that a Reviewing Representative to whom Confidential Material is disclosed ceases to be engaged to provide services to the Receiving Party, then access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every such person shall continue to be bound by the provisions of this NDA.

6. Confidential Material shall be physically and/or electronically marked "Confidential Material or "Confidential Pursuant to Section 583 of the Public Utilities Code, or "Produced Pursuant to Section 583 of the Public Utilities Code", or marked with words of similar purport. All Confidential Material shall be maintained by the Receiving Party and by Reviewing Representatives in a secure manner. Access to Confidential Material shall be limited to those Reviewing Representatives specifically authorized pursuant to paragraphs 8 and 9 of this Agreement.

7. Subject to the terms of this NDA, Reviewing Representatives of the Receiving Party shall be entitled to access the Protected Materials. Reviewing Representatives may make copies of Confidential Materials, but such copies become Confidential Materials. Reviewing Representatives may make notes of Confidential Materials, which shall be treated as Confidential Materials under this NDA if those notes disclose the contents of Confidential Materials.

8. Confidential Materials shall be treated as confidential by the Receiving Party and by the Reviewing Representatives, in accordance with the Nondisclosure Certificate executed pursuant to paragraph 9 of this Agreement. Confidential Materials shall not be used except as necessary for the conduct of this CPUC proceeding, or other relevant CPUC proceeding, in

which the Study is involved, and shall not be disclosed in any manner to any person except: (i) designated Reviewing Representatives of the Receiving Party; and (ii) designated Reviewing Representatives' employees and administrative personnel, such as clerks, secretaries, and word processors, to the extent necessary to assist the Reviewing Representatives, provided that they shall first ensure that such personnel are familiar with the terms of this NDA. Reviewing Representatives shall adopt suitable measures to maintain the confidentiality of Confidential Materials they have obtained pursuant to this NDA and consistent with this NDA, and shall treat such Confidential Materials in the same manner as they treat their own most highly confidential information. The Receiving Party shall be liable for any unauthorized disclosure or use by its Reviewing Representatives or by their employees or administrative staff. In the event any Reviewing Representative is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) to disclose any of Confidential Materials, they shall immediately inform PG&E of the request, and PG&E may, at its sole discretion and cost, direct any challenge or defense against the disclosure requirement, and the Reviewing Representative shall cooperate in good faith with PG&E either to oppose the disclosure of the Confidential Materials consistent with applicable law, or to obtain confidential treatment of them by the person or entity who wishes to receive them prior to any such disclosure.

9. The Receiving Party shall identify its proposed individuals who will review the confidential Materials (Reviewing Representative(s)) to PG&E. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise access Confidential Material pursuant to this Agreement unless and until the Reviewing Representative has first executed and delivered to PG&E a Nondisclosure Certificate in the form set forth in Appendix A to this Agreement ("Nondisclosure Certificate"). Attorneys qualified as Reviewing Representatives are responsible for ensuring that all persons under their employment, instruction, supervision or control who require access to Confidential Material comply with this Agreement and execute and deliver to PG&E a Nondisclosure Certificate

10. A Reviewing Representative may disclose Confidential Material to any other Reviewing Representative qualified to access the Confidential Material under paragraphs 8 and 9 if appropriate, as long as both Reviewing Representatives have executed and delivered a Nondisclosure Certificate to PG&E. In the event that any Reviewing Representative to whom Confidential Material is disclosed ceases to be engaged in the Proceeding or is employed or retained for a position whereby that person is no longer qualified to be a Reviewing Representative under paragraphs 8 and 9 of this Agreement, such person shall no longer be permitted access to Confidential Material and must comply with the return and destruction requirements of paragraph 5 of this Agreement within 30 days of ceasing to be a Reviewing Representative, and without waiting for a written request from PG&E. Every person who has signed and delivered a Nondisclosure Certificate shall continue to be bound by the provisions of this Agreement and the Nondisclosure Certificate, even if such person is no longer engaged in the Proceeding.

11. If the Receiving Party intends to submit or use any Confidential Material in any proceeding involving the Study such that the submission or use would result in a public disclosure of such Confidential Material, including, without limitation, the presentation of prepared testimony, cross-examination, briefs, comments, protests, or other presentations before the Commission, counsel for the Receiving Party shall communicate with counsel for PG&E as soon as possible and, where practicable, not later than five (5) business days prior to such use, and both counsel shall constructively explore means of identifying the Confidential Material so that the confidentiality thereof may be reasonably protected (including, but not limited to, submission of testimony and briefs under seal, and clearing the hearing room during examination, discussion, or argument concerning Confidential Material), while at the same time enabling an effective presentation. If PG&E and the Receiving Party are unable to agree upon a procedure to protect the confidentiality of the Confidential Material, the Receiving Party shall request an order from the principal hearing officer in the proceeding involving the Study, and PG&E reserves the right to oppose the Receiving Party's request. Except as expressly provided for herein, no use may be made of Confidential Material that would fail to protect its

confidentiality without such an order from the principal hearing officer.

12. The principal hearing officer in any proceeding involving the Study retains the discretion to review and evaluate the facts and circumstances involved in any proposed use of Confidential Material in Commission hearings, and the flexibility to respond in whatever manner is most appropriate under the circumstances, including the holding of in camera hearings.

13. Nothing in this NDA shall be construed as precluding PG&E or the Receiving Party from objecting to the use at hearings or before the Commission of Confidential Material on any legal grounds. To the extent that Confidential Material is discussed, analyzed or is otherwise the subject of consideration during any conference or other session before the Commission, only Reviewing Representatives may be present for such sessions.

14. Failure to designate information or documents as Confidential Material prior to disclosure shall not be deemed a waiver in whole or in part of the claim of confidentiality, and PG&E shall have the right to designate or re-designate such information and documents at any time. Upon receipt of notice from PG&E of any new designation or re-designation, the Receiving Party thereafter shall treat said information or documents according to the new designation or re-designation, and/or will endeavor to return all copies of any newly designated or re-designated documents to PG&E in exchange for copies of the documents with the new designation.

15. Any waiver of any provision of this NDA, or a waiver of a breach hereof, must be in writing and signed by both Parties to be effective. Any waiver of a breach of this NDA, whether express or implied, shall not constitute a waiver of a subsequent breach hereof.

16. PG&E makes no representations regarding current or future rates, customer bill savings, customer benefits, programs, cost allocation or any other matters involving the provision of utility service that may arise in connection with the Study or Confidential Materials provided under this Non-Disclosure Agreement.

17. This Agreement shall be governed and construed according to the laws of the State of California.

18. This NDA sets forth the complete understanding of the parties hereto with respect

to the subject matter hereof as of the date set forth above. This Agreement supersedes any prior understandings, discussions, or course of conduct (oral and written). Any modification or waiver of the provisions of this NDA must be written, must be executed by both PG&E and the Receiving Party, and shall not be implied by any usage of trade or course of conduct.

19. PG&E may agree at any time to remove the "Confidential Materials" designation from Confidential Materials provided to such party if, in PG&E's opinion, confidentiality protection is no longer required. In such a case, PG&E will notify the Receiving Party of the change of designation.

20. If any provision hereof is unenforceable or invalid, it shall be given effect to the extent it may be enforceable or valid, and such unenforceability or invalidity shall not affect the enforceability or validity of any other provision of this NDA.

21. This Agreement may be executed in separate counterparts by PG&E and the Receiving Party, each of which shall be fully effective as to the party executing it.

22. The principal hearing officer in any proceeding in which the Study is involved shall resolve any disputes arising from this NDA. Prior to presenting any dispute arising from this NDA to the principal hearing officer, PG&E and the Receiving Party shall use their best efforts to resolve the dispute.

IN WITNESS WHEREOF, the undersigned have executed this Non-Disclosure Agreement as of the date entered below on behalf of PG&E and the Receiving Party.

PACIFIC GAS AND ELECTRIC COMPANY

Dated: ____________________

By: ______________________

(Name of Attorney)

Law Department
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, CA 94120
Telephone: (415) 973-xxxx
Fax: (415) 973-0516
Email: XXX@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

RECEIVING PARTY

Dated: ______________________________

Signature: ____________________________

Name: ______________________________

Title: _______________________________

Company/Firm: _______________________

Representing (name of party): _____________

____

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design, including Real Time Pricing, to Revise its Customer Energy Statements, and to Seek Recovery of Incremental Expenditures (U 39 M) Caption to change depending on case	Application 10-03-014 (filed March 22, 2010) Caption to change depending on case

NONDISCLOSURE CERTIFICATE FOR AGRICULTURAL AGGREGATION STUDY UNDER THE AGRICULTURAL SETTLEMENT

I certify my understanding that access to Confidential Material is provided to me pursuant to the terms and restrictions of the Nondisclosure Agreement ("NDA") for use in proceedings where the Study is involved. I have been given a copy of and have read the NDA and agree to be bound by it. I understand that the contents of Confidential Material, including any notes or memorandum or other form of information which copy, characterize or disclose such material, shall not be disclosed to anyone other than in accordance with the NDA and shall be used only for the purpose of the above-captioned proceeding, or any CPUC proceeding in which the Study is involved. I agree to honor the confidentiality of Confidential Material as specified in the NDA, including without limitation Paragraphs 8, 10 and_11.

Dated:________________

Signature: ________________________

Name: ________________________

Title: ________________________

Company/Firm: ________________________

Representing (name of party): ________________

Business Address: ________________________

____

Business Phone: ________________________

Business Fax: ________________________

Email: ________________________

Appendix 4 to Exhibit C - Ag Settlement

________, 2011

Mr. Steven Moss
M. Cubed
2325 Third Street, Suite 344
San Francisco, CA 94107

Re: Letter Agreement to Implement 2011 GRC Phase 2 Agricultural Settlement, Account Aggregation Study

Dear Mr. Moss,

The purpose of this letter agreement is to confirm the arrangements for your firm to perform and receive payment for the consultant services set forth in the Agricultural Settlement Aggregation Study, Item 3, "Proposed Scope of Work for Agricultural Consultants" (Consultants Work Scope).

Your firm is identified in the 2011 GRC 2 Agricultural Settlement ("Agricultural Settlement"), Account Aggregation Study, Item 3 ("Study"), to perform the work in the Consultants Work Scope. Your subcontractors will include but not be limited to Aspen Environmental Group, Economic Insights and MRW & Associates. All work for the study by you and your subcontractors is described in the Consultants Work Scope, which is attached to this letter agreement as Appendix A. By executing this letter agreement you express your agreement with the Consultants Work Scope.

The Agricultural Settlement provides that PG&E will pay an amount not to exceed $100,000 for the work performed by you and your subcontractors, including expenses, for services within the Consultants Work Scope. You and your subcontractors are responsible for providing documentation for charges for the services and expenses to perform the Consultants Work Scope and for which you request PG&E to pay under the Agricultural Settlement. Your invoices and documentation are required to provide the detail specified in Appendix B to this letter agreement. As the primary contractor, M.Cubed will be responsible for submitting to PG&E the invoices and documentation for your subcontractors, as well as for M.Cubed itself. PG&E will remit payments consistent with the Consultants Work Scope and this letter agreement to M.Cubed. M.Cubed will be responsible for remitting payments to each of its subcontractors for amounts owed to them.

Payment by PG&E to M.Cubed shall not be due until the Commission has issued its final decision approving the Agricultural Settlement. If the Commission does not approve the Agricultural Settlement, PG&E shall not be liable to remit any payment(s) to M.Cubed for work the Agricultural Consultants may have undertaken prior to the Commission decision.

M.Cubed and its subcontractors may not represent to any agricultural customer that PG&E is making any representations regarding current or future rates programs, cost allocation or any other matters involving its provision of utility service in connection with the Study. M.Cubed and its subcontractors agree that the Consultants Work Scope and the Study are for the purpose of developing and collecting data and other information as described in the Study.

The data and information provided to M.Cubed and its subcontractors by PG&E, as well as M.Cubed and its subcontractors' analyses regarding specific customers under this Scope of Work may only used by M.Cubed and its subcontractors for purposes of the Study and proceedings involving the study. The data, information, and analyses regarding specific customers may only be shared with PG&E, Commission staff under Public Utilities Code § 583, and qualified Reviewing Representatives for third parties who have executed the NDA for the Aggregation Study (provided, however, that the M.Cubed and its subcontractors may share with each individual customer specific data, information and analyses that are limited to that individual customer). This provision is effective upon M.Cubed's execution of this letter agreement and remains in effect for the period(s) that the NDAs for the aggregation study remain in effect.

M.Cubed and PG&E agree to be bound by the terms and provisions of this Letter Agreement and appendices and intend that this Letter Agreement and its appendices be interpreted and treated as a unified, integrated agreement to implement the Consultants Work Scope in the Agricultural Settlement. M.Cubed further agrees that its subcontractors agree to be similarly bound.

In the event the Commission does not approve the Agricultural Settlement this agreement will become null and void, and PG&E will not be liable for any further payments to M.Cubed and its subcontractors.

Very truly yours,

(PG&E signature)

On behalf of M.Cubed, I agree to the terms of this Letter Agreement to Implement 2011 GRC 2 Agricultural Settlement, Account Aggregation Study

By: ______________________________

Dated: ____________________, 2011

Attachments

Cc: Michael Boccadoro, AECA
Wendy Illingworth (Economic Insights)
Laura Norin (MRW & Associates)
Richard McCann (Aspen Environmental Group)

ATTACHMENT B

M.Cubed and its subcontractors will provide documentation for the amounts expended under the Consultants Work Scope with the following detail

Hourly rate:
The hourly rate for the following individuals to provide services are:

Steve Moss	$205 per hour
Richard McCann	$205 per hour
Wendy Illingworth	$190 per hour
Laura Norin	$205 per hour
Others	Rate not to exceed $205 per hour

Invoices:
Invoices shall provide the following details:

- Hourly information on types of work performed, the individual involved and the compensated requested:
  e.g., 4 hours on yy date, for customer meetings by Mr. R on operations XX dollars
  e.g. 8 hours reviewing data for study by Ms. W XX dollars

- Expenses will be detailed and accompanied by receipts for items of $75 or more:
  e.g. Mr. R, xx hours driving to customer site, at $$ per mile, on yy date XX dollars
  e.g. copying or faxing on yy date XX dollars
  e.g. reimbursement for meals, on yy date for Mr. R trip to customer XX dollars

Copies of the subcontractors' invoices shall be provided to PG&E.
Unreasonable expenses shall not be reimbursed.
Requests for reimbursements to PG&E shall be expected not less frequently than on a bi-monthly basis.

Invoices and accompanying documentation shall be sent to the following address:

Amrit Singh/Dan Pease
c/o Ann Mah
PG&E - Analysis & Rates Department
P.O. Box 770000, Mail Code B10B
San Francisco, CA 94177

E-mail: alm4@pge.com

(END OF APPENDIX F)

APPENDIX G

Revenue Allocations Expressed as Percentage Change in Customer Class Average Annual Rates Resulting From Adopted Settlement Agreement

Customer Class	Percentage Increase (Decrease)
Residential	0.6
Small Light & Power	0.2
Medium Light & Power	(0.9)
Schedule E-19	(0.9)
Streetlights	1.5
Standby	(1.7)
Agriculture	(1.0)
Schedule E-20	(1.0)
Total	0.0

(END OF APPENDIX G)