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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