BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2014. **(U 39 M)**	**Application No.**

[DRAFT]

GENERAL RATE CASE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

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July 2, 2012

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GENERAL RATE CASE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

By this 2014 test year General Rate Case (GRC) Application, Pacific Gas and Electric Company (PG&E or the Company) asks the California Public Utilities Commission (Commission or CPUC), effective January 1, 2014, to increase electric and gas rates and charges to collect the reasonable level of revenue requirements that PG&E needs to continue to provide safe and reliable gas and electric service to its customers.[1/]

As explained by PG&E Corporation's Chairman, Chief Executive Officer and President (Exhibit (PG&E-1), Chapter 1), PG&E is embarking on a strategy to address three broad areas:

- Executing on a "back to basics" strategy to improve our operations;
- Strengthening PG&E's culture so that identifying issues and driving continuous improvement become deeply ingrained in PG&E's mindset and behavior; and
- Rebuilding relationships with PG&E's customers, communities and other stakeholders.

Executing on these strategies, this GRC places priority on minimizing risk and improving safety. In this GRC, PG&E charts a course for first quartile performance in public

1/ This application is submitted pursuant to Article 2 of the Commission's Rules of Practice and Procedure and the Commission's Rate Case Plan adopted in Decision (D.) 07-07-004 ("Rate Case Plan").

and employee safety. (Exhibit (PG&E-1), Chapter 3.) This GRC also forecasts increases in gas distribution expense and capital necessary to meet Senate Bill 705 requirements for implementation of industry best practices for gas pipeline safety.

PG&E's emphasis on safety and risk is consistent with Executive Director Clanon's March 5, 2012 letter to PG&E. The Executive Director's letter described a process by which the Commission's Consumer Protection and Safety Division (CPSD) would hire independent consultants to review operational and public safety issues regarding PG&E's forecast and PG&E would have an opportunity to formally respond to the review. PG&E looks forward to the review and to its opportunity to respond.

In this Application, PG&E requests that the Commission increase gas and electric distribution and generation base revenue requirements by a total of $1.250 billion, effective January 1, 2014, as compared to 2014 authorized and pending revenues.

Notwithstanding this request, the rates of the approximately 49 percent of PG&E's electric customers either covered under the California Alternative Rates for Energy (CARE) program or whose usage is at or below 130 percent of baseline will not, pursuant to current law, increase as a result of this request.[2/] PG&E's request represents a 7.8 percent increase over the projected 2013 total combined gas and electric revenue of $16.086 billion.

I. STATEMENT OF RELIEF AND AUTHORITY SOUGHT

Table 1 shows the bill impact for non-CARE electric residential customers using 550 kWh and 850 kWh per month and for non-CARE gas residential customers using 37 therms per month.

2/ Any increase to rates for customers either covered under the CARE program or whose usage is at or below 130 percent of baseline are constrained by California Public Utilities Code Sections 739.1 and 739.9 and are independent of the outcome of this proceeding.

Table 1
Impact on Non-CARE Residential Customer Bills

Monthly Residential Customer Usage	Current 2012 Avg. Bill	Proposed 2014 Bill Increase	Increase	2012 to 2014 Percent Increase
Electric:				
550 kWh	**$ 89.73**	**$ 94.37**	**$ 4.64**	**5.17%**
850 kWh	**$185.92**	**$204.32**	**$18.40**	**9.90%**
Gas:				
37 Therms	**$ 46.13**	**$ 52.80**	**$6.67**	**14.46%**

Table 2 sets forth PG&E's request for an increase in base revenue amounts.

Table 2
Increase in Base Revenue Amounts
(Millions of Dollars)

	2012 Authorized and Pending Revenue Requirement[3/]	2014 Authorized and Pending Revenue Requirement[4/]	2014 Proposed Revenue Requirement	Increase: 2012 Authorized to 2014 Proposed		Increase: 2014 Authorized and Pending to 2014 Proposed	
Gas Distribution	**$1,288**	**$1,324**	**$1,783**	**$ 495**	**38.4%**	**$ 459**	**34.7%**
Electric Distribution	**3,633**	**3,768**	**4,333**	**700**	**19.3%**	**565**	**15.0%**
Electric Generation	**1,707**	**1,737**	**1,962**	**255**	**14.9%**	**225**	**13.0%**
Total	**$6,629**	**$6,829**	**$8,079**	**$1,450**	**21.9%**	**$1,250**	**18.3%**

*** Some numbers in the tables in this Application may not add up due to rounding.**

Because PG&E's total electric and gas revenue requirements consist largely of energy procurement and other costs not included in the gas distribution, electric distribution, and electric generation revenue requirements presented in the GRC, the percentage increases over total revenue requirements are substantially lower than the percentage increases shown above. Table 3 below shows the total gas distribution revenue requirement increase over the 2012 total authorized gas revenue requirement and the 2013 forecast total gas revenue

3/ These amounts include revenues from PG&E's 2011 GRC Decision 11-05-018, adjusted for attrition. The amounts also include the authorized and pending revenue requirements associated with the Cornerstone Project, Market Redesign and Technology Upgrade (MRTU), Fuel Cell Project, Vaca-Dixon PV Pilot Project, SmartMeter and meter reading. These amounts exclude pension costs.

4/ See footnote 3.

requirement. Also presented in Table 3 is the combined electric distribution and electric generation revenue requirement increase over the 2012 total electric revenue requirement and the 2013 forecast total electric revenue requirement.

Table 3
GRC Revenue Increase Over Total Revenues
(Millions of Dollars)

	2012 Authorized Revenues	2014 Revenue Increase Over 2012	% Increase over 2012 Revenues	2013 Revenue Forecast	2014 GRC Increase Over 2013	% Increase Over 2013 Revenues
Gas	$ 3,450	$ 495	14.3%	$ 3,486	$459	13.2%
Electric	12,435	955	7.7%	12,600	791	6.3%
Total	$15,885	$1,450	9.1%	$16,086	$1,250	7.8%

In this 2014 Application, PG&E also asks the Commission to authorize the Company to implement adjustments for the 2015 and 2016 attrition years. PG&E estimates the attrition adjustment will yield the revenue requirement increases set forth in Table 4.

Table 4
Attrition Year Revenue Requirement Increases
(Millions of Dollars)

	Gas Distribution	Electric Distribution	Electric Generation	Total
2015	$201	$220	$69	$491
2016	$166	$234	$98	$499

II. ACCEPTANCE OF THE NOTICE OF INTENT

On July 2, 2012, PG&E tendered its 2014 GRC Notice of Intent (NOI). On ________, 2012, the Division of Ratepayer Advocates (DRA) accepted the tendered documents.[5/] Consistent with the Rate Case Plan, PG&E served a Notice of Availability of the NOI on all appearances in its last general rate case, and sent a letter to Chief ALJ Karen Clopton verifying service.[6/]

5/ *See* Opinion Modifying Energy Rate Case Plan, D.07-07-004, *mimeo*, p. A-11.

6/ *Id.*, pp. A-11 to A-12.

III. SUMMARY OF REASONS FOR PG&E'S REQUEST AND SPECIFIC AREAS OF INCREASE

A. Reasons for Requested Relief

PG&E will provide detailed support for its 2014 GRC Application in the prepared testimony and workpapers accompanying this filing.[7] The key reasons for the requested increase in revenue requirements are:

- Increases in the costs of delivering energy safely to customers, maintaining reliability, and providing responsive customer service;
- Need for substantial capital investments to replace aging infrastructure;
- Need for capacity-driven additions;
- Recovery of costs for depreciation associated with PG&E's plant investments; and
- Costs of complying with governmental regulations and orders applicable to PG&E's extensive electric and gas systems and facilities.

The specific areas of increase for the gas distribution and electric distribution and generation functions are discussed separately below.

B. Specific Areas of Increase

The fundamental elements comprising PG&E's gas distribution and electric distribution and generation revenue requirement increases are: Operations and Maintenance (O&M) expense; Customer Services expense; Administrative and General (A&G) expense; payroll taxes, franchise fees, and uncollectibles (FF&U); return, taxes, and depreciation; change in depreciation rates; and changes in Other Operating Revenue.

1. Gas Distribution Revenue Requirement

Table 5 lists the elements composing the gas distribution revenue requirement increase over the amounts the Commission adopted in PG&E's 2011 GRC, as adjusted per footnote 3, supra.

7/ *Id.*, pp. A-11 to A-12.

Table 5
Elements of Gas Distribution Revenue Requirement Increase

Area	(Millions of Dollars)
O&M Expense	$171
Customer Service Expense	10
A&G Expense	64
Increase in Other Operating Revenue	(4)
FF&U, Other Adjs, Taxes Other than Income	25
Return, Taxes, Depreciation, and Amortization	193
Increase in Retail Revenue Amount	$459

2. Electric Distribution Revenue Requirement

Table 6 lists the elements composing the electric distribution revenue requirement increase over the amounts the Commission adopted in PG&E's 2011 GRC, as adjusted per footnote 3, supra.

Table 6
Elements of Electric Distribution Revenue Requirement Increase

Area	(Millions of Dollars)
O&M Expense	$5
Customer Service Expense	15
A&G Expense	80
Decrease in Other Operating Revenue	14
FF&U, Other Adjs, Taxes Other than Income	46
Return, Taxes, Depreciation, and Amortization	405
Increase in Retail Revenue Amount	$565

3. Electric Generation Revenue Requirement

Table 7 lists the elements composing the electric generation revenue requirement increase over the amounts the Commission adopted in PG&E's 2011 GRC, as adjusted per footnote 3, supra.

Table 7
Elements of Electric Generation Revenue Requirement Increase

Area	(Millions of Dollars)
O&M Expense	$76
Customer Service Expense	0
A&G Expense	80
Increase in Other Operating Revenue	(3)
FF&U, Other Adjs, Taxes Other than Income	(108)
Return, Taxes, Depreciation, and Amortization	180
Increase in Retail Revenue Amount	$225

IV. AMOUNT OF REVENUE INCREASE BY CUSTOMER CLASS

The illustrative percentage change for each customer class is presented in Table 8.

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Table 8
Illustrative Revenue Allocation By Customer Class: Gas

Customer Class	Revenues at Present (4/1/12) Rates ($000)	Proposed Illustrative Revenue Allocation ($000)	Revenue Change ($000)	Percentage Change
Core Retail – Bundled				
Residential	$2,342,313	$2,684,875	$342,562	14.6%
Commercial, Small	646,342	730,574	84,232	13.0%
Commercial, Large	42,204	45,236	3,032	7.2%
Natural Gas Vehicle (Uncompressed Service)	11,080	11,261	182	1.6%
Natural Gas Vehicle (Compressed Service)	4,533	4,484	-48	-1.1%
Noncore Retail – Transportation Only				
Industrial Distribution	50,911	65,287	14,375	28.2%
Industrial Transmission	109,583	121,388	11,805	10.8%
Industrial Backbone	555	616	61	10.9%
Electric Generation	65,622	68,517	2,895	4.4%
Natural Gas Vehicle (Uncompressed Service)	334	362	29	8.6%
Wholesale –				
Alpine Natural Gas	41	41	0	0.0%
Coalinga	149	149	0	0.0%
Island Energy	33	33	0	0.0%
Palo Alto	1,451	1,451	0	0.0%
West Coast Gas - Castle	103	132	28	27.5%
West Coast Gas – Mather, Distribution	142	178	36	25.4%
Unbundled Backbone Transmission and Storage	174,832	174,832	0	0.0%
Total	$3,450,228	$3,909,415	$459,187	13.3%

The revenue changes set forth above are illustrative only. The gas distribution revenue change has been allocated to customer classes in proportion to the gas distribution base revenue allocation adopted in PG&E's most recent Biennial Cost Allocation Proceeding (BCAP) Decision.

Table 9
Illustrative Revenue Allocation By Customer Class: Electric

Customer Class Bundled	Total Revenue at 3/1/12 Rates ($000)	Proposed Illustrative Class Revenue ($000)	Revenue Change ($000)	Percentage Change
Residential	$5,152,860	$ 5,475,133	$ 322,272	6.3%
Small L&P	1,470,249	1,580,369	110,120	7.5%
Medium L&P	1,284,389	1,364,875	80,486	6.3%
E-19 Total	1,551,902	1,646,741	94,838	6.1%
Streetlights	69,889	73,133	3,244	4.6%
Standby	57,808	60,831	3,023	5.2%
Agriculture	870,309	930,310	60,000	6.9%
E-20 Total	1,122,193	1,182,491	60,298	5.4%
Total Bundled	$ 11,579,599	$ 12,313,882	$ 734,283	6.3%
Direct Access				
Residential	$ 95,449	$ 105,971	$ 10,522	11.0%
Small L&P	16,383	17,758	1,375	8.4%
Medium L&P	108,288	116,371	8,083	7.5%
E-19 Total	240,671	257,816	17,145	7.1%
Standby	967	1,021	54	5.5%
Agriculture	3,113	3,345	232	7.5%
E-20 Total	267,566	283,901	16,335	6.1%
Total Direct Access	$732,437	$786,182	$53,745	7.3%

The revenue changes set forth above are illustrative only. They have been allocated to each customer class consistent with the current allocation practice approved by Decision 11-12-053.

A. Summary Supporting Increase

The costs and associated revenue requirements that are the subject of this Application are those estimated to occur in calendar year 2014. These costs include all O&M and A&G expenses, depreciation, taxes, and a fair return on rate base for the electric and gas distribution and electric generation functions that PG&E performs. PG&E is presenting this GRC in an "unbundled" format, consistent with all of PG&E's GRCs since 2003. All the costs have been separated into Unbundled Cost Categories (UCCs) and aggregated into business functional areas. This Application does not address revenue requirement changes in the areas of electric transmission, gas transmission and storage, public purpose programs and conservation programs, except for the purpose of allocating common costs. In the area of common cost allocation, this Application asks that the Commission approve the allocations of A&G expenses and common plant to all UCCs for use in other non-GRC Commission ratemaking mechanisms.

Consistent with the Rate Case Plan, PG&E developed and presented its test year revenue requirement estimates using the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. (See, for example, Exhibit (PG&E-1), Chapter 5 of the testimony supporting this Application.) In addition, PG&E augmented this traditional FERC-account presentation with a complete description of its operational activities and costs necessary to conduct its utility business in a safe and reliable manner.

As done since the 2003 GRC, PG&E has organized its operational activity and cost forecasts by Major Work Category (MWC), the basic unit of work activity PG&E uses for its operational planning, budgeting and managing purposes.[8/] PG&E's testimony regarding costs, organized by MWC, is found in Exhibits (PG&E-3) through (PG&E-7) and Exhibit (PG&E-9). PG&E's internal accounting system (using software that SAP AG developed) keeps track of PG&E's operational costs by MWC. The entries in this system are expressed in "SAP dollars," which include certain overhead costs, i.e., in addition to the direct costs of an activity, like labor and materials, they contain indirect costs such as benefits and payroll taxes.

For capital costs, PG&E's presentation by MWC is similar to the presentation PG&E has made since its 2003 GRC.

For O&M expense, the SAP dollars for a given MWC typically may be booked to several different FERC accounts. The testimony in Exhibit (PG&E-2), Chapters 2 through 6, explains how the forecast SAP dollars in each MWC are determined and then assigned to their corresponding FERC accounts. In turn, aggregating all of the MWC expense to a particular FERC account provides the corresponding FERC-dollar forecast.

8/ PG&E's A&G Department costs are managed by cost centers, not MWCs.

V. COST OF CAPITAL/AUTHORIZED RATE OF RETURN

The Rate Case Plan requires a utility to "use the most recently authorized rate of return in its calculations" supporting its results of operations presentation.[9] Accordingly, PG&E has used the authorized cost of capital information set forth in Decisions 07-12-049, 08-05-035 and 09-10-016.

VI. REVENUES AT PRESENT RATES IN THE RESULTS OF OPERATIONS REPORT

PG&E's rates and charges for electric and gas service are set forth in PG&E's electric and gas tariffs on file with this Commission. The Commission has approved these tariffs in decisions, orders, and resolutions. Exhibit B sets forth PG&E's present electric and gas rates.

At rates currently in effect, PG&E estimates that, in 2014, its electric and gas distribution operations would be able to earn returns on rate base of 6.31 percent and 2.20 percent respectively, as shown in detail in Exhibit H. These forecast rates of return on rate base equate to returns on common equity for the electric distribution function of 6.58 percent, and for the gas distribution function of -1.32 percent. For the generation function, at present rates the 2014 return on rate base would be 6.31 percent, which equates to 6.57 percent return on common equity.

VII. EXHIBITS AND PREPARED TESTIMONY

The testimony exhibits in this Application consist of chapters setting forth the testimony of witnesses familiar with the subject matter of their testimony. The witnesses present PG&E's principles and policies for managing its utility functions to provide safe and reliable service, and the factual support for the forecasted costs.

VIII. EXHIBITS AND SPECIAL STUDIES FURNISHED

Each testimony exhibit generally contains an introductory chapter explaining the contents of the exhibit. In addition, each chapter generally contains an introduction which summarizes the information and material discussed in the chapter. A list of the testimony

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9/ D.07-07-004, *mimeo*, p. A-30.

exhibits showing their contents and identifying the sponsoring witnesses is attached to this Application as Appendix 1.

IX. OTHER MATTERS RELATED TO PG&E'S APPLICATION

A. Relationship to Decision 09-09-020 (Pension)

The revenue requirement for the pension contributions in the period 2014 through 2016 will be collected through the Pension Cost Recovery Mechanism, not in the 2014 GRC request. Consistent with the revenue requirements adopted in Decision 09-09-020, capitalized pension costs through 2013 are included in GRC rate base effective January 1, 2014.

B. Cornerstone Improvement Project

In Application 08-05-023, PG&E proposed the Cornerstone Improvement Project (Cornerstone Project), which was intended to improve the resiliency and reliability of PG&E's electric distribution system. In D.10-06-048, the Commission approved some, but not all, of the key Cornerstone Project elements. Since that decision was issued, PG&E has commenced work on the approved Cornerstone Project and has provided the Commission with annual reports to discuss its progress. The Cornerstone Project ends in 2013. PG&E's 2014 GRC forecast does not include expenditures to complete work previously approved in the Cornerstone decision. That work is handled separately in accordance with the Cornerstone decision.

C. Balancing Accounts and Memorandum Accounts

PG&E is proposing that new two-way balancing accounts be adopted for costs associated with: gas leak survey and repair (see Exhibit (PG&E-3), Chapter 6); major emergencies that are not covered by the Catastrophic Event Memorandum Account (see Exhibit (PG&E-4), Chapter 10); FERC relicensing for hydroelectric facilities and pending new license conditions (see Exhibit (PG&E-6), Chapter 2); and implementation of Nuclear Regulatory Commission (NRC) rulemaking requirements for PG&E's Diablo Canyon Power Plant (see Exhibit (PG&E-6), Chapter 3). PG&E proposes to continue the existing one-way balancing account and tracking account for vegetation management (see Exhibit (PG&E-4), Chapter 8).

PG&E proposes to eliminate existing balancing accounts for the distribution integrity management program (DIMP) (see Exhibit (PG&E-3), Chapter 4); and SmartMeter™ Program deployment and meter reading (see Exhibit (PG&E-5), Chapters 5 and 10). PG&E also proposes to close the Service Disconnection Memorandum Account (see Exhibit (PG&E-5), Chapter 4); the Assembly Bill 32 Cost of Implementation Fee accounts (see Exhibit (PG&E-7), Chapter 7); the non-demand response portion of the MRTU Memorandum Account (see Exhibit (PG&E-10, Chapter 9); and, depending on update testimony, the Tax Memorandum Account (see Exhibit (PG&E-2), Chapter 14).

D. A&G

As the Commission explained in PG&E's 1999 GRC decision, "A&G expenses are of a general nature and are not directly chargeable to any specific utility function. They include general office labor and supply expenses and items such as insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses."[10] A&G expenses support the Company's provision of safe and reliable gas and electric distribution and electric generation services. The process for forecasting A&G is set forth in the testimony and supporting workpapers of Exhibit (PG&E-9).

E. Depreciation Study

As in past GRCs, PG&E has engaged a depreciation expert to study PG&E's plant additions, retirement and net salvage data, to review present depreciation rates and to recommend changes to those rates for its distribution plant as necessary. The depreciation study is described in Exhibit (PG&E-2), Chapter 11.

F. Post Test Year Ratemaking -- Attrition

PG&E seeks an attrition ratemaking for 2015 and 2016 designed to increase the Company's authorized revenues to reflect predetermined increases in capital costs due to its

10/ D.00-02-046, *mimeo*, pp. 243-244.

ongoing investments in infrastructure, as well as pre-determined increases in wages and other expenses due to inflation. (See Exhibit (PG&E-11).) The primary driver of attrition increases in this GRC is capital investment which drives increases in rate base and depreciation expense, irrespective of inflation. As for the expense portion of attrition, PG&E's attrition proposal includes a fixed and pre-forecasted escalation of labor, medical costs, goods and services that PG&E must purchase to operate its business, as well as other adjustments described in Exhibit (PG&E-11). Finally, under its attrition proposal PG&E is proposing throughout the GRC cycle to allow for upward or downward adjustments to revenue for certain exogenous changes under a "Z factor" mechanism, similar to the mechanism adopted for other California utilities. The Company estimates that its attrition proposal will result in an increase of approximately $491 million for 2015 and an additional $499 million for 2016.

G. Studies and Information Required by Previous Commission Policy Statements or Decisions

In its decision on PG&E's 1984 GRC, the Commission ordered PG&E to provide, among other things a "presentation of levels of wages and salaries estimated by the utility for comparison with similar wages and salaries paid in the marketplace."[11/] Pursuant to PG&E's 2011 GRC decision, this study will not include information related to long-term incentives, which are not funded by customers.[12/] Also pursuant to PG&E's 2011 GRC decision, PG&E has not proffered studies of multifactor productivity in this case.[13/]

Other compliance items are listed in Exhibit (PG&E-10), Chapter 8.

H. Recorded Data

Pursuant to the Rate Case Plan's requirement regarding recorded data, PG&E is presenting recorded data, in results of operations format, for base year 2011.

11/ D.83-12-068; 14 CPUC 2d 15, 263, Ordering Paragraph No. 15.d.

12/ D.11-05-018, *mimeo*, p. 1-19 (Settlement Agreement Section 3.12(l)).

13/ D.11-05-018, *mimeo*, p. 1-19 (Settlement Agreement Section 3.12(k)).

I. Previously Litigated Issues

One A&G issue in this case deals with recovery of that portion of management employee compensation which is at risk pursuant to the Company's Short-Term Incentive Plan (STIP). In this GRC, PG&E seeks recovery of STIP only for eligible non-officer employees. In PG&E's 1999 GRC, the Commission allowed 50 percent recovery of PG&E's requested payments, with PG&E's request based on a target of 1.0 (out of a potential payout of 2.0).[14/] The issue was not specifically addressed in the 2003 and 2007 Distribution and Generation Settlements. Although not precedential, PG&E's 2011 GRC Settlement Agreement reflects a reduction in STIP recovery to reflect parties' arguments in the case.[15/]

Since the Commission's decision in PG&E's 1999 GRC, the Commission has spoken on this issue in several rate case decisions and authorized recovery of 100 percent of incentive compensation programs.[16/] Similarly, in this case, PG&E will demonstrate that recovery of the full STIP revenue requirement for non-officer employees (as described in Exhibit (PG&E-8), Chapter 5 is reasonable and consistent with Commission precedent in recent GRCs.

Another issue in this case is recovery of premiums for Directors and Officers (D&O) liability insurance. The Commission has acknowledged that D&O liability insurance is a necessary and reasonable cost of doing business, provides significant benefit to customers, is critical to obtaining and maintaining qualified directors and officers, and therefore had previously allowed the utility to include the costs of this insurance in rates.[17/] However, the Commission later reversed course, authorizing the utility to include only 50 percent of D&O costs in rates, notwithstanding its reaffirmation that D&O insurance was a necessary cost of doing business.[18/] Because the Commission has consistently acknowledged the necessity of

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14/ D.00-02-046, *mimeo*, p. 256.

15/ D.11-05-018, *mimeo*, p. 1-12 (Settlement Agreement Section 3.6.1).

16/ D.04-07-022, *mimeo*, pp. 213-217 (SCE 2003 GRC); D.06-05-016, *mimeo*, pp. 127-132 (SCE 2006 GRC); D.08-07-046, *mimeo*, p. 22 (Sempra 2008 GRC).

17/ D.87-12-066, 26 CPUC 2d, 422 (SCE 1988 GRC).

18/ D.96-01-011, 64 CPUC 2d 241, 319 (SCE 1996 GRC).

this type of coverage, PG&E requests that the Commission revisit this policy and authorize PG&E to recover the full amount of D&O insurance premiums in rates.

PG&E has computed working cash, consistent with its prior GRC filings and in conformity with Commission Standard Practice (SP) U-16. PG&E's practice of excluding customer deposits from working cash follows Commission precedent involving PG&E that have endorsed the SP U-16 methodology. PG&E has not followed the Commission's treatment of SCE on this issue, which the Commission in PG&E's 2007 GRC characterized as "something of an aberration."[19]

PG&E has also computed rate base using a forecast of nuclear fuel. PG&E's proposal to include nuclear fuel in rate base contrasts with the Commission's treatment of SCE.[20] However, given ongoing turmoil in the financial markets and lessons learned about excessive leveraging – and consistent with industry practice throughout the US -- PG&E will once again show that nuclear fuel must be financed with a combination of equity and long-term debt, the same as for other nuclear plant. If PG&E is not permitted to include nuclear fuel in rate base, PG&E will not be able to recover its costs of financing this specially designed material, which has no use other than at the Diablo Canyon Power Plant.

J. Rate Case Plan Matters Determined in Phase 2 of this Proceeding or in Other Proceedings

1. Electric Marginal Costs and Revenue Allocation

The Rate Case Plan requires electric utilities to submit, as part of the GRC application, cost allocation studies by classes of service and marginal cost data in sufficient detail to allow the development of rates for each customer class, with a complete electric rate design proposal to be filed no later than 90 days after filing of the application.[21] Consistent with PG&E's practice in prior GRCs, PG&E will present in "Phase 2" of this proceeding,

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19/ *Cf.* D.07-03-044, *mimeo*, pp. 201-202 (PG&E 2007 GRC) with D.04-07-022, *mimeo*, pp. 249-255 (SCE 2003 GRC) and subsequent SCE GRC decisions; also see language supportive of PG&E's position in D.08-07-046, *mimeo*, pp. 28-29 (Sempra 2008 GRC).

20/ See D.06-05-016, *mimeo*, pp. 272-273 (SCE 2006 GRC).

21/ D.07-07-004, *mimeo*, p. A-22.

electric marginal cost, revenue allocation, and rate design, on a later timetable than the revenue requirement showing in "Phase 1."[22/] Given this practice, PG&E is not including electric marginal costs and revenue allocation in this application. Gas marginal costs, revenue allocation, and rate design are addressed in the Biennial Cost Allocation Proceeding.

2. Demand Side Management (Public Purpose) Program Issues

The Rate Case Plan requirement for demand-side management (DSM) program information[23/] has been superseded by Public Utilities Code Sections and distinct Commission proceedings and decisions governing DSM program offerings, cost-effectiveness and funding levels. In addition to the Commission DSM proceedings which authorize and fund DSM programs, Public Utilities Code Section 382 provides that electric low-income programs (low-income energy efficiency and the California Alternate Rates for Energy low-income rate discount programs) continue to be funded at levels not less than those in effect during 1996. Further, Public Utilities Code Section 890 requires the Commission to establish a non-bypassable gas surcharge to fund gas energy efficiency, low-income and public interest research and development programs.

The Application requests funding for one component of the low-income Energy Savings Assistance DSM program-- the Natural Gas Appliance Testing (NGAT) Program. (See Exhibit (PG&E 5), Chapter 7). The NGAT program is not covered by other cost proceedings or recovery mechanisms and has historically been covered in the GRC.

3. Current Resource Plan

The Rate Case Plan, developed long before the advent of Electric Industry Restructuring in California, requires electric utilities to submit their "current Resource Plan."[24/] The Commission now reviews the long-term electric procurement plans of the

22/ See Assigned Commissioner Bohn's ruling in PG&E's 2007 GRC (issued February 3, 2006), directing PG&E to "file a separate application for Phase 2 issues" on the grounds that such "treatment of Phase 2 issues is consistent with recent GRC proceedings and the Commission's responsibility under Pub. Util. Code § 1701.5 to complete ratesetting proceedings within 18 months."

23/ D.07-07-004, *mimeo*, p. A-32.

24/ *Id.*

state's major electric utilities in the Long Term Procurement Plan Proceeding, which typically occurs every two years The Commission approved PG&E's most recent long-term electric procurement plan in Decision 12-01-033. Similarly, PG&E's gas resource plan for its core gas customers is addressed in the Biennial Cost Allocation Proceeding.

K. Estimates by Account

PG&E has presented its O&M and A&G estimates in this Application by FERC Account. In addition, as discussed above, PG&E has presented its estimates by MWC consistent with how the Company plans, budgets, and manages it operations.

L. Guidelines or Directions Affecting PG&E's GRC Presentation

The Rate Case Plan provides that "[w]hen controlling affiliates provide guidelines or directions to the Company's presentation, these shall be set forth in the direct showing or available in the workpapers."[25/] PG&E Corporation has been apprised of and has participated in the development of this GRC application, including direction in the development of Exhibit (PG&E-1), Chapter 1. PG&E Corporation departments also provided information regarding the cost of services the PG&E Corporation provides to the Utility, which are described in Exhibit (PG&E-9).

M. Proposal for Implementing Proposed Revenue Change at the Beginning of the Test Year

Proposals for implementing electric and gas revenue changes on January 1, 2014, are set forth in Exhibit (PG&E-10), Chapters 6 (electric) and 7 (gas), and the workpapers supporting those chapters.

X. WORKPAPERS

PG&E's witnesses have prepared workpapers supporting PG&E's exhibits in accordance with the requirements of the Rate Case Plan. *PG&E intends to request inclusion of the workpapers in the record of the 2014 GRC.* Therefore, when the witnesses adopt their prepared and rebuttal testimony along with any other testimony that may be submitted, the witnesses will also sponsor and adopt their workpapers, if any.

25/ *Id.*

XI. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

A. Statutory Authority

PG&E files this Application pursuant to Sections 451, 454, 728, 729, 740.4 and 795 of the Public Utilities Code, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of the Commission.

B. Categorization - Rule 2.1.(c)

PG&E proposes that this Application be categorized as a "ratesetting" proceeding.

C. Need for Hearing - Rule 2.1(c)

PG&E anticipates that hearings will be requested. PG&E's proposed schedule is set forth in subsection E, below.

D. Issues to be Considered - Rule 2.1(c)

The principal issues are whether:

1. The proposed revenue requirement for the electric distribution function in 2014 is just and reasonable and that the Commission should authorize PG&E to reflect the adopted electric distribution revenue requirement in rates.

2. The proposed revenue requirement for the gas distribution function in 2014 is just and reasonable and that the Commission should authorize PG&E to reflect the adopted gas distribution revenue requirement in rates.

3. The proposed revenue requirement for the electric generation function in 2014 is just and reasonable and the Commission should authorize PG&E to reflect the adopted revenue requirement in rates.

4. With respect to the Gas Distribution organization described in Exhibit (PG&E-3):

    a. The two-way balancing account for leak survey and repair described in Exhibit (PG&E-3), Chapter 6, should be adopted.

5. With respect to the Electric Distribution organization described in Exhibit (PG&E-4):

a. The one-way balancing account and tracking account for Vegetation Management described in Exhibit (PG&E-4), Chapter 8, should be continued.

b. The two-way balancing account for major emergency costs not covered by the Catastrophic Event Memorandum Account described in Exhibit (PG&E-4), Chapter 10, should be adopted.

c. The annual PG&E Electric Tariff Rule 20A work credit allocation amount of $41.3 million adopted in the 2011 General Rate Case decision should be extended through 2016, as described in Exhibit (PG&E-4), Chapter 18.

d. The rate design for LED streetlights described in Exhibit (PG&E-4), Chapter 19, should be adopted.

6. With respect to the Customer Care organization described in Exhibit (PG&E-5):

a. The costs recorded in the Service Disconnection Memorandum Accounts as of December 31, 2013, are reasonable and should be recoverable through the mechanism described in Exhibit (PG&E-10), Chapter 9.

b. The proposed changes to customer fees (i.e., the non-sufficient funds fee and reconnection fees) described in Exhibit (PG&E-10), Chapter 4, are just and reasonable and should be adopted.

c. The reporting requirements concerning the SmartMeter™ program specifically identified in Exhibit (PG&E-5), Chapter 10, are no longer required;

7. With respect to the Energy Supply organization described in Exhibit (PG&E-6):

a. The decommissioning and fuel oil inventory costs described in Exhibit (PG&E-6), Chapter 4 should be authorized.

b. The expenditure of $1 million in capital costs above the amount authorized in Decision 10-04-028 for the fuel cell projects should be authorized because the additional expenditure was reasonable and necessary, as explained in Exhibit (PG&E-6), Chapter 4.

c. The credit to the Electric Generation Revenue Requirement with funds received as a result of Department of Energy (DOE) litigation and revenue overcollections associated with PG&E's Utility-Owned Generation Photovoltaic Program, should be authorized, as described in Exhibit (PG&E-6), Chapter 6.

d. The two-way balancing accounts for Hydroelectric Relicensing Costs and Nuclear Regulatory Costs described in Exhibit (PG&E-6), Chapter 1, should be approved.

8. With respect to the Shared Services and IT organizations described in Exhibit (PG&E-7):

a. The fees associated with Assembly Bill 32 that were recorded prior to 2014 in the memorandum account authorized in Decision 10-12-026 should be authorized for recovery as described in Exhibit (PG&E-7), Chapter 7.

9. With respect to the Human Resources and Administrative and General (A&G) functions described in Exhibits (PG&E-8) and (PG&E-9):

a. The full STIP revenue requirement for eligible non-officer employees is just and reasonable, as described in Exhibit (PG&E-8), Chapter 5, and should be approved.

b. The full cost of Directors and Officers liability insurance is just and reasonable, as described in Exhibit (PG&E-9), Chapter 3, and should be approved.

10. The budget reporting requirements adopted in PG&E's 2011 GRC, as described in Exhibit (PG&E-1), Chapter 5, should be continued.

11. The proposed allocation of common costs (A&G expenses and common plant) should be approved for use in other, non-GRC Commission ratemaking mechanisms.

12. The proposed attrition adjustments for 2015 and 2016 for the electric and gas distribution and electric generation functions are just and reasonable and that PG&E may implement the annual attrition adjustments by compliance advice letters.

13. The proposed computations for working cash are in conformity with Standard Practice (SP) U-16, just and reasonable and should be approved.

14. The forecasts of generation rate base, including the inclusion in rate base of forecast nuclear fuel inventory, are just and reasonable, and should be approved.

15. The revisions to existing balancing and memorandum accounts, described in Exhibit (PG&E-10), Chapter 9, are just and reasonable, and should be approved.

E. Proposed Schedule – Rule 2.1(c)

The Rate Case Plan identifies certain activities associated with processing a GRC and specifies the dates by which these activities should occur. The Rate Case Plan contemplates separate sets of evidentiary hearings on an Applicant's direct testimony and rebuttal testimony. In previous GRCs, the Commission has consolidated these hearings, resulting in a more efficient process. Consolidated hearings are reflected in the schedule proposed below. The schedule also introduces milestones pertaining to the process described in the Executive Director's March 5, 2012 letter to PG&E. Specifically, PG&E has included items pertaining to the submission of the third-party reviews being conducted by the CPSD, as well as responsive testimony to those reviews.

PG&E's proposed schedule is as follows:

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Activity	Date
File Application	_________, 2012
Informal Public Workshop	December __, 2012
Prehearing Conference	January 11, 2013
CPSD Reports Submitted	February __, 2013
DRA report served	February 15, 2013
Intervenor reports served	March 8, 2013
Rebuttal testimony served (including Responsive Testimony to CPSD Reports)	April 5, 2013
Public Participation Hearings	TBD
Evidentiary Hearings begin	April 22, 2013
Evidentiary Hearings end	May 24, 2013
Comparison Exhibit	June 14, 2013
Opening Briefs	July 12, 2013
Reply Briefs	August 9, 2013
Update Filing	September 6, 2013
Update Hearing	September 16, 2013
ALJ PD	November 1, 2013
Comments on PD	November 22, 2013
Reply to PD Comments	November 29, 2013
Oral Argument, if ordered	December 5, 2013
Decision	December 19, 2013

As described in the testimony supporting this Application, this GRC proposes many important new measures, measures that must be planned in advance. To ensure that such measures are implemented in 2014, it is important that the Commission decision be issued prior to the end of 2013. PG&E's larger capital projects take at least several months advance planning. Should a final decision be issued during 2014, the benefits from some of the larger projects could be delayed beyond the schedule anticipated by PG&E's testimony.

PG&E is committed to doing what it can to accelerate this proceeding. In this regard, PG&E has included in the above schedule an informal public workshop that will be open to all parties. At this workshop, PG&E will provide parties with a roadmap of the filing, summarize the contents of the exhibits and be available to answer questions. PG&E will also be open to participation in settlement discussions, whether mandated or not, in order to remove or narrow issues from further litigation. PG&E will be looking for additional ways during the course of the case to help ensure that it proceeds on schedule.

F. Legal Name and Principal Place of Business - Rule 2.1(a)

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E's principal place of business is San Francisco, California. Its post office address is Post Office Box 7442, San Francisco, California 94120.

G. Correspondence and Communication Regarding This Application - Rule 2.1.(b)

All correspondence and communications regarding this Application should be addressed to Steven W. Frank and Shelly J. Sharp at the addresses listed below:

Steven W. Frank
Law Department
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, California 94120
Telephone: (415) 973-6976
Fax: (415) 973-5520
E-mail: SWF5@pge.com

Shelly J. Sharp
Senior Director
Pacific Gas and Electric Company
77 Beale Street, B9A
San Francisco, California, 94105
Telephone: (415) 973-2636
Fax: (415) 973-6520
E-Mail: SSM3@pge.com

Overnight hardcopy delivery:

Steven W. Frank
Law Department
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, California 94105

H. Articles of Incorporation - Rule 2.2

PG&E is, and since October 10, 1905, has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Restated

Articles of Incorporation, effective April 12, 2004, is on record before the Commission in connection with PG&E's Application 04-05-005, filed with the Commission on May 3, 2004. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules.

I. Balance Sheet and Income Statement - Rule 3.2(a)(1)

PG&E's balance sheet and an income statement for the three months ending March 31, 2012, are contained in Exhibit A of this Application.[26]

J. Statement of Presently Effective Rates - Rule 3.2(a)(2)

The presently effective gas and electric rates PG&E proposes to modify are set forth in Exhibit B of this Application.

K. Statement of Proposed Changes and Results of Operations at Proposed Rates - Rule 3.2(a)(3)

The proposed changes and the Results of Operations at Proposed Rates are set forth in Exhibits C and D of this Application.

L. General Description of PG&E's Electric and Gas Department Plant - Rule 3.2(a)(4)

A general description of PG&E's Electric Department and Gas Department properties, their original cost, and the depreciation reserve applicable to these properties are shown in Exhibit E of this Application.

M. Summary of Earnings - Rules 3.2(a)(5) and 3.2(a)(6)

Exhibit F shows for the recorded year 2011 the revenues, expenses, rate bases and rate of return for PG&E's Electric and Gas Departments. (For purposes of this draft application, 2010 data has been provided because 2011 data is currently unavailable. For the final application, 2011 data will be provided.)

N. Statement of Election of Method of Computing Depreciation Deduction for Federal Income Tax - Rule 3.2(a)(7)

A statement of the method of computing the depreciation deduction for federal income tax purposes is included in Exhibit G.

26/ See also Exhibit (PG&E-10), Chapter 2.

O. Most Recent Proxy Statement - Rule 3.2(a)(8)

PG&E's most recent proxy statement dated April 2, 2012 was filed with the Commission in application A.12-04-018 on April 20, 2012. This proxy statement is incorporated herein by reference.

P. Type of Rate Change Requested - Rule 3.2(a)(10)

This proposed change reflects changes in PG&E's base revenues to reflect the costs PG&E incurs to own, operate and maintain its gas and electric plant and to enable PG&E to provide service to its customers.

Q. Notice and Service of Application - Rule 3.2(b)-(d)

Within ten (20) days after filing this Application, PG&E will mail a notice stating in general terms the proposed revenues, rate changes, and ratemaking mechanisms requested in this Application to the parties listed in Exhibit I, including the State of California and cities and counties served by PG&E. A Notice of Availability of the Application and attachments is being served on the parties of record in PG&E's 2011 GRC (A.09-12-020) in accordance with Rule 1.9.(d) and the Rate Case Plan.[27/]

PG&E will publish in newspapers of general circulation in each county in its service territory a notice of filing this Application. PG&E will also include notices with the regular bills mailed to all customers affected by the proposed changes.

R. Exhibit List and Statement of Readiness

PG&E is ready to proceed with this case based on the testimony of witnesses regarding the facts and data contained in the accompanying exhibits in support of the revenue request set forth in this Application. A list of PG&E's testimony by Exhibit and Chapter number is attached as Appendix 1.

XII. REQUEST FOR COMMISSION ORDERS

PG&E requests that the Commission issue appropriate orders:

27/ See D.07-07-004, *mimeo*, pp. A-12 to A-13.

1. Finding that the proposed revenue requirement for the electric distribution function in 2014 is just and reasonable and that PG&E may reflect the adopted electric distribution revenue requirement in rates;

2. Finding that the proposed revenue requirement for the gas distribution function in 2014 is just and reasonable and that PG&E may reflect the adopted gas distribution revenue requirement in rates;

3. Finding the proposed revenue requirement for the electric generation function in 2014 are just and reasonable and that PG&E may reflect the adopted electric generation revenue requirement in rates;

4. With respect to the Gas Distribution organization described in Exhibit (PG&E-3), finding that:

   a. The two-way balancing account for leak survey and repair described in Exhibit (PG&E-3), Chapter 6, should be adopted.

5. With respect to the Electric Distribution organization described in Exhibit (PG&E-4), finding that:

   a. The one-way balancing account and tracking account for Vegetation Management described in Exhibit (PG&E-4), Chapter 8, should be continued.

   b. The two-way balancing account for major emergency costs not covered by the Catastrophic Event Memorandum Account described in Exhibit (PG&E-4), Chapter 10, should be adopted.

   c. The annual PG&E Electric Tariff Rule 20A work credit allocation amount of $41.3 million adopted in the 2011 General Rate Case decision should be extended through 2016, as described in Exhibit (PG&E-4), Chapter 18.

   d. The rate design for LED streetlights described in Exhibit (PG&E-4), Chapter 19, should be adopted.

6. With respect to the Customer Care organization described in Exhibit (PG&E-5), finding that:

a. The costs recorded in the Service Disconnection Memorandum Accounts as of December 31, 2013, are reasonable and should be recoverable through the mechanism described in Exhibit (PG&E-10), Chapter 9.

b. The proposed changes to customer fees (i.e., the non-sufficient funds fee and reconnection fees) described in Exhibit (PG&E-10), Chapter 4, are just and reasonable and should be adopted.

c. The reporting requirements concerning the SmartMeter™ program specifically identified in Exhibit (PG&E-5), Chapter 10 are no longer required.

7. With respect to the Energy Supply organization described in Exhibit (PG&E-6), finding that:

a. The decommissioning and fuel oil inventory costs described Exhibit (PG&E-6), Chapter 4, should be authorized.

b. The expenditure of $1 million in capital costs above the amount authorized in Decision 10-04-028 for the fuel cell projects should be authorized because the additional expenditure was reasonable and necessary, as explained in Exhibit (PG&E-6), Chapter 4.

c. The credit to the Electric Generation Revenue Requirement with funds received as a result of Department of Energy (DOE) litigation and revenue overcollections associated with PG&E's Utility-Owned Generation Photovoltaic Program should be authorized, as described in Exhibit (PG&E-6), Chapter 6.

d. The two-way balancing accounts for Hydroelectric Relicensing Costs and Nuclear Regulatory Costs described in Exhibit (PG&E-6), Chapter 1 should be approved.

8. With respect to the Shared Services and IT organizations described in Exhibit (PG&E-7), finding that:

a. Fees associated with Assembly Bill 32 that were recorded prior to 2014 in the memorandum account authorized in Decision 10-12-026 should be authorized for recovery, as described in Exhibit (PG&E-7), Chapter 7.

9. With respect to the Human Resources and Administrative and General (A&G) functions described in Exhibits (PG&E-8) and (PG&E-9), finding that:

a. Recovery of the full STIP revenue requirement for eligible non-officer employees is just and reasonable, as described in Exhibit (PG&E-8), Chapter 5, and should be approved.

b. Recovery of the full cost of Directors and Officers liability insurance is just and reasonable, as described in Exhibit (PG&E-9), Chapter 3, and should be approved.

10. Finding that the budget reporting requirements adopted in PG&E's 2011 GRC, as described in Exhibit (PG&E-1), Chapter 5, should be continued.

11. Finding that the proposed allocation of common costs (A&G expenses and common plant) is approved for use in other, non-GRC Commission ratemaking mechanisms.

12. Finding that the proposed attrition adjustments for 2015 and 2016 for the electric and gas distribution and electric generation functions are just and reasonable and that PG&E may implement the annual attrition adjustments by compliance advice letters.

13. Finding that the proposed computations for working cash are in conformity with Standard Practice (SP) U-16 are just and reasonable, and should be approved.

14. Finding that the forecasts of generation rate base, including the inclusion in rate base of forecast nuclear fuel inventory, are just and reasonable, and should be approved.

15. Finding that the revisions to existing balancing and memorandum accounts, described in Exhibit (PG&E-10), Chapter 9, are just and reasonable, and should be approved.

16. Establishing a schedule for the remainder of this proceeding pursuant to the Commission's Rate Case Plan and issuing other orders that will authorize the requested relief to become effective no later than January 1, 2014; and

17. Granting such additional relief as the Commission may deem proper.

Respectfully submitted,

MICHELLE L. WILSON
STEVEN W. FRANK

By: ______________________________
STEVEN W. FRANK

Law Department
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, California 94120
Telephone: (415) 973-6976
Fax: (415) 973-5520
E-mail: SWF5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

July 2, 2012

VERIFICATION

I, the undersigned, say:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and am authorized, pursuant to Code of Civil Procedure Section 466, paragraph 3, to make this verification for and on behalf of said corporation, and I make this verification for that reason; I have read the foregoing pleading and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed at San Francisco, California, on _____________, 2012.

____
OFFICER

CERTIFICATE OF SERVICE

I, the undersigned, state that I am a citizen of the United States and employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California 94105.

I am readily familiar with the business practice of Pacific Gas and Electric Company for collection and processing of correspondence for mailing with the United States Postal Service. In the ordinary course of business, correspondence is deposited with the United States Postal Service the same day it is submitted for mailing.

On ______, 2012, I caused to be served a true copy of:

GENERAL RATE CASE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

Via Electronic mail on ________, 2012, addressed to:

All Parties of Record in A.09-12-020 (See Attached Service Lists)

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated this __th day of ______________, 2012 at San Francisco, California.

Redacted

Exhibit A

Balance Sheet and Income Statement

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)	
	Three Months Ended March 31,	
(in millions)	2012	2011
Operating Revenues		
Electric	$ 2,771	$ 2,616
Natural gas	869	980
Total operating revenues	3,640	3,596
Operating Expenses		
Cost of electricity	859	888
Cost of natural gas	343	508
Operating and maintenance	1,366	1,226
Depreciation, amortization, and decommissioning	584	490
Total operating expenses	3,152	3,112
Operating Income	488	484
Interest income	1	2
Interest expense	(168)	(171)
Other income, net	23	17
Income Before Income Taxes	344	332
Income tax provision	113	131
Net Income	231	201
Preferred stock dividend requirement	3	3
Income Available for Common Stock	$ 228	$ 198

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 45	$ 304
Restricted cash ($56 and $51 related to energy recovery bonds at March 31, 2012 and December 31, 2011, respectively)	385	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $80 and $81 at March 31, 2012 and December 31, 2011)	926	992
Accrued unbilled revenue	614	763
Regulatory balancing accounts	1,425	1,082
Other	821	840
Regulatory assets ($227 and $336 related to energy recovery bonds at March 31, 2012 and December 31, 2011, respectively)	1,024	1,090
Inventories		
Gas stored underground and fuel oil	97	159
Materials and supplies	273	261
Income taxes receivable	212	242
Other	188	213
Total current assets	6,010	6,326
Property, Plant, and Equipment		
Electric	36,329	35,851
Gas	12,015	11,931
Construction work in progress	2,011	1,770
Total property, plant, and equipment	50,355	49,552
Accumulated depreciation	(16,106)	(15,898)
Net property, plant, and equipment	34,249	33,654
Other Noncurrent Assets		
Regulatory assets	6,565	6,506
Nuclear decommissioning trusts	2,134	2,041
Income taxes receivable	413	384
Other	330	331
Total other noncurrent assets	9,442	9,262
TOTAL ASSETS	$ 49,701	$ 49,242

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	March 31, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,401	$ 1,647
Long-term debt, classified as current	50	50
Energy recovery bonds, classified as current	321	423
Accounts payable		
Trade creditors	873	1,177
Disputed claims and customer refunds	658	673
Regulatory balancing accounts	641	374
Other	522	417
Interest payable	788	838
Income taxes payable	118	118
Deferred income taxes	165	199
Other	1,562	1,628
Total current liabilities	7,099	7,544
Noncurrent Liabilities		
Long-term debt	11,418	11,417
Regulatory liabilities	4,927	4,733
Pension and other postretirement benefits	3,391	3,325
Asset retirement obligations	1,620	1,609
Deferred income taxes	6,347	6,160
Other	2,071	2,070
Total noncurrent liabilities	29,774	29,314
Commitments and Contingencies (Note 10)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at March 31, 2012 and December 31, 2011	1,322	1,322
Additional paid-in capital	4,181	3,796
Reinvested earnings	7,259	7,210
Accumulated other comprehensive loss	(192)	(202)
Total shareholders' equity	12,828	12,384
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 49,701	$ 49,242

Exhibit B

Statement of Presently Effective Rates

Comparison of Transportation Rate Changes

The forecast rates provided herein are for discussion purposes only. The actual rates, when approved by the CPUC, can be different. These rates are for transportation service only and exclude the commodity cost of natural gas. PG&E Co. will not accept responsibility for any use of the rates provided in this document.

Rate Schedules	1/1/2012 (1)	Average Rate No PPP	4/1/2012 (2)	% Chg from Jan 1, 2012	Average Rate No PPP	% Chg from Jan 2012	
Residential (G-1, GM, GS, GT)							
Transportation Charge ($/Therm)							
Tier 1	$0.49375	$0.63187	$0.51872	5.06%	$0.63849	1.0%	Avg. Summer (Apr-Oct)
Tier 2	$0.78999	$0.58782	$0.82996	5.06%	$0.59025	0.4%	Avg. Winter (Jan-Mar, Nov-Dec)
Average Rate from RTP		$0.60721			$0.61116	0.7%	Avg. Annual
Residential Natural Gas Vehicle (G1-NGV)							
Customer Charge	$0.41425		$0.41425	0.00%			
Transportation Charge ($/therm) implemented 2/1/06	$0.23895		$0.28818	20.60%			
Small Commercial (G-NR1)							
Customer Charge 0 - 5.0 therms ($/day)	$0.27048		$0.27048	0.00%			
Customer Charge 5.1 - 16.0 therms ($/day)	$0.52106		$0.52106	0.00%			
Customer Charge 16.1 - 41.0 therms ($/day)	$0.95482		$0.95482	0.00%			
Customer Charge 41.1 - 123.0 therms ($/day)	$1.66489		$1.66489	0.00%			
Customer Charge >123.1 therms ($/day)	$2.14936		$2.14936	0.00%			
Transportation Charge ($/Therm)							
Summer (1st 4,000)	$0.32848	$0.37783	$0.31815	-3.15%	$0.36921	-2.3%	Avg. Summer
Summer (Excess)	$0.12816		$0.12948	1.04%			
Winter (1st 4,000)	$0.40177	$0.40547	$0.38822	-3.37%	$0.39433	-2.7%	Avg. Winter
Winter (Excess)	$0.15675		$0.15800	0.80%			
		$0.39343			$0.38338	-2.6%	Avg. Annual
Large Commercial (G-NR2)							
Customer Charge ($/Day)	$4.95518		$4.95518	0.00%			
Transportation Charge ($/Therm)							
Summer (1st 4,000)	$0.32848	$0.15392	$0.31815	-3.15%	$0.15400	0.1%	Avg. Summer
Summer (Excess)	$0.12816		$0.12948	1.04%			
Winter (1st 4,000)	$0.40177	$0.18404	$0.38822	-3.37%	$0.18391	-0.1%	Avg. Winter
Winter (Excess)	$0.15675		$0.15800	0.80%			
		$0.16646			$0.16646	0.0%	Avg. Annual
Residential Transport-Only (G-CT)							
Transportation Charge ($/Therm)							
Tier 1	$0.49375		$0.51872	5.06%			
Tier 2	$0.78999		$0.82996	5.06%			
Small Commercial Transport-Only (G-CT)							
Transportation Charge ($/Therm)							
Summer (1st 4,000)	$0.32848		$0.31815	-3.15%			
Summer (Excess)	$0.12816		$0.12948	1.04%			
Winter (1st 4,000)	$0.40177		$0.38822	-3.37%			
Winter (Excess)	$0.15675		$0.15800	0.80%			
Large Commercial Transport-Only (G-CT)							
Transportation Charge ($/Therm)							
Summer (1st 4,000)	$0.32848		$0.31815	-3.15%			
Summer (Excess)	$0.12816		$0.12948	1.04%			
Winter (1st 4,000)	$0.40177		$0.38822	-3.37%			
Winter (Excess)	$0.15675		$0.15800	0.80%			
G-PPP CORE CUSTOMERS							
Residential Non-Care	$0.08618		$0.08618	0.00%			
Residentail CARE	$0.05651		$0.05651	0.00%			
Small Commercial	$0.05295		$0.05295	0.00%			
Large Commercial	$0.09495		$0.09495	0.00%			

Comparison of Transportation Rate Changes

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Rate Schedules	1/1/2012 (1)	Average Rate No PPP	4/1/2012 (2)	% Chg from Jan 1, 2012	Average Rate No PPP	% Chg from Jan 2012
Industrial (G-NT)						
Customer Access Charge ($/Day)						
0 to 5,000 therms	$1.92033		$1.92033	0.0%		
5,001 to 10,000 therms	$5.72055		$5.72055	0.0%		
10,001 to 50,000 therms	$10.64712		$10.64712	0.0%		
50,001 to 200,000 therms	$13.97326		$13.97326	0.0%		
200,001 to 1,000,000 therms	$20.27408		$20.27408	0.0%		
1,000,001 therms and above	$171.97677		$171.97677	0.0%		
Transportation Charge ($/Therm)						
Backbone	0.01091	$0.01243	0.01091	0.00%	$0.01243	0.0%
Transmission	$0.03712	$0.03892	$0.03712	0.00%	$0.03892	0.0%
Distribution (Summer) Tier 1	$0.17303	$0.14207	$0.17303	0.00%	$0.14207	0.0%
Distribution (Summer) Tier 2	$0.12360		$0.12360	0.00%		
Distribution (Summer) Tier 3	$0.11350		$0.11350	0.00%		
Distribution (Summer) Tier 4	$0.10560		$0.10560	0.00%		
Distribution (Summer) Tier 5	$0.03712		$0.03712	0.00%		
Distribution (Winter) Tier 1	$0.22076		$0.22076	0.00%		
Distribution (Winter) Tier 2	$0.15402		$0.15402	0.00%		
Distribution (Winter) Tier 3	$0.14039		$0.14039	0.00%		
Distribution (Winter) Tier 4	$0.12973		$0.12973	0.00%		
Distribution (Winter) Tier 5	$0.03712		$0.03712	0.00%		
G-PPP Noncore Customers						
Backbone/Transmission	$0.03968		$0.03968	0.00%		
Distribution	$0.04733		$0.04733	0.00%		
Electric Generation G-EG						
Transportation Charge:						
Backbone Transportation Charge ($/therm)	0.01154	$0.01176	0.01154	0.00%	$0.01176	0.0%
Distribution/Transmission Charge ($/Therm)	$0.03105	$0.03208	$0.03105	0.00%	$0.03208	0.0%
Wholesale G-WSL						
Customer Access Charge ($/Day)						
Palo Alto	$150.56186		$150.56186	0.00%		
Coalinga	$45.15649		$45.15649	0.00%		
West Coast Gas-Mather	$23.97173		$23.97173	0.00%		
West Coast Gas - Castle	$26.23134		$26.23134	0.00%		
Island Energy	$30.59540		$30.59540	0.00%		
Alpine Natural Gas	$10.21019		$10.21019	0.00%		
Transportation Charge ($/Therm)						
Palo Alto	$0.02799	$0.02971	$0.02799	0.00%	$0.02971	0.0%
Coalinga	$0.02799	$0.03468	$0.02799	0.00%	$0.03468	0.0%
West Coast Gas - Mather (Transmission)	$0.02799	$0.03715	$0.02799	0.00%	$0.03715	0.0%
West Coast Gas - Mather (Distribution)	$0.15336	$0.16251	$0.15336	0.00%	$0.16251	0.0%
West Coast Gas - Castle (Distribution)	$0.12267	$0.13744	$0.12267	0.00%	$0.13744	0.0%
Island Energy	$0.02799	$0.05283	$0.02799	0.00%	$0.05283	0.0%
Alpine Natural Gas	$0.02799	$0.03412	$0.02799	0.00%	$0.03412	0.0%

Comparison of Transportation Rate Changes

The forecast rates provided herein are for discussion purposes only. The actual rates, when approved by the CPUC, can be different. These rates are for transportation service only and exclude the commodity cost of natural gas. PG&E Co. will not accept responsibility for any use of the rates provided in this document.

Rate Schedules	1/1/2012 (1)	Average Rate No PPP	4/1/2012 (2)	% Chg from Jan 1, 2012	Average Rate No PPP	% Chg from Jan 2012
Natural Gas Vehicle - Uncompressed (G-NGV1)						
Customer Charge ($/Day)	$0.44121		$0.44121	0.00%		
Transportation Charge ($/Therm)	$0.04663	$0.12818	$0.04664	0.02%	$0.12817	0.0%
Natural Gas Vehicle - Compressed (G-NGV2)						
Customer Charge ($/Day)	$0.00		$0.00	0.00%		
Transportation Charge ($/Therm)	$1.27134	$1.35169	$1.27087	-0.04%	$1.35121	0.0%
Natural Gas Vehicle - Uncompressed (G-NGV4)						
Customer Access Charge ($/Day)						
0 to 5,000 therms	$1.92033		$1.92033	0.0%		
5,001 to 10,000 therms	$5.72055		$5.72055	0.0%		
10,001 to 50,000 therms	$10.64712		$10.64712	0.0%		
50,001 to 200,000 therms	$13.97326		$13.97326	0.0%		
200,001 to 1,000,000 therms	$20.27408		$20.27408	0.0%		
1,000,001 therms and above	$171.97677		$171.97677	0.0%		
Transportation Charge ($/Therm)						
Transmission	$0.03042	$0.03221	$0.03042	0.00%	$0.03221	0.0%
Distribution (Summer) Tier 1	$0.17303	$0.14207	$0.17303	0.00%	$0.14207	0.0%
Distribution (Summer) Tier 2	$0.12360		$0.12360	0.00%		
Distribution (Summer) Tier 3	$0.11350		$0.11350	0.00%		
Distribution (Summer) Tier 4	$0.10560		$0.10560	0.00%		
Distribution (Summer) Tier 5	$0.03042		$0.03042	0.00%		
Distribution (Winter) Tier 1	$0.22076		$0.22076	0.00%		
Distribution (Winter) Tier 2	$0.15402		$0.15402	0.00%		
Distribution (Winter) Tier 3	$0.14039		$0.14039	0.00%		
Distribution (Winter) Tier 4	$0.12973		$0.12973	0.00%		
Distribution (Winter) Tier 5	$0.03042		$0.03042	0.00%		
Liquefied Natrual Gas (G-LNG)	$0.16886		$0.16886	0.00%		
G-PPP Natural Gas Vehicle/Liquid Natural Gas	$0.03197		$0.03197	0.00%		

Notes:

1) Rates are based on 1/1/2012 implementation of the Annual Gas True-Up AL 3257-G-A for noncore and AL 3267-G for core

2) Rates are based on 4/1/2012 implementation of Adopted Baseline Quantites in PG&E's 2011 GRC Phase 2 D.11-12-053, and core deaveraging as adopted in 2010 BCAP D.10-06-035, implemented in April 2012 AL 3286-G.

Comparison of Transportation Rate Changes

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Rate Schedules	1/1/2012 (1)	Average Rate No PPP	4/1/2012 (2)	% Chg from Jan 1, 2012	Average Rate No PPP	% Chg from Jan 2012
Comparison of Gas Accord Tariffs						
Gas Schedule G-AA				% Chg		% Chg
Path	Usage Rate		Usage Rate	From 1/1/12		From 1/1/12
Redwood to On-System (Per Dth)	$0.33920		$0.33920	0.00%		
Baja to On-System (Per Dth)	$0.37520		$0.37520	0.00%		
Silverado to On-System (Per Dth)	$0.19020		$0.19020	0.00%		
Mission to On-System (Per Dth)	$0.00000		$0.00000	0.00%		
Gas Schedule G-AAOFF						
Path	Usage Rate		Usage Rate			
Redwood to Off-System (Per Dth)	$0.3392		$0.3392	0.00%		
Baja to Off-System (Per Dth)	$0.3752		$0.3752	0.00%		
Silverado to Off-System (Per Dth)	$0.3392		$0.3392	0.00%		
Mission to Off-System (Per Dth)	$0.3392		$0.3392	0.00%		
Mission to Off-System Storage Withdrawls (Per Dth)	$0.0000		$0.0000	0.00%		
Gas Schedule G-AFT	Reservation Rate		Reservation Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to On-System (Per Dth)	$5.4576	$8.3437	$5.4576	0.00%	$8.3437	0.00%
Redwood to On-System Core Procurement Groups Only (Per Dth)	$4.6534	$6.4678	$4.6534	0.00%	$6.4678	0.00%
Baja to On-System (Per Dth)	$6.0418	$9.2370	$6.0418	0.00%	$9.2370	0.00%
Baja to On-System Core Procurement Groups Only (Per Dth)	$5.2883	$7.3504	$5.2883	0.00%	$7.3504	0.00%
Silverado to On-System (Per Dth)	$3.1639	$4.6413	$3.1639	0.00%	$4.6413	0.00%
Mission to On-System (Per Dth)	$3.1639	$4.6413	$3.1639	0.00%	$4.6413	0.00%
	Usage Rate		Usage Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to On-System (Per Dth)	$0.1032	$0.00830	$0.1032	0.00%	$0.00830	0.00%
Redwood to On-System Core Procurement Groups Only (Per Dth)	$0.0693	$0.00960	$0.0693	0.00%	$0.00960	0.00%
Baja to On-System (Per Dth)	$0.1140	$0.00890	$0.1140	0.00%	$0.00890	0.00%
Baja to On-System Core Procurement Groups Only (Per Dth)	$0.0784	$0.01060	$0.0784	0.00%	$0.01060	0.00%
Silverado to On-System (Per Dth)	$0.0545	$0.00590	$0.0545	0.00%	$0.00590	0.00%
Mission to On-System (Per Dth)	$0.0545	$0.00590	$0.0545	0.00%	$0.00590	0.00%
Mission to On-System Storage Withdrawls (Conversion option from Firm ON-System Rewood or Baja Path only)	$0.0000	$0.0000	$0.0000	0.00%	$0.0000	0.00%
Gas Schedule G-AFTOFF	Reservation Rate		Reservation Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to Off-System (Per Dth)	$5.4576	$8.3437	$5.4576	0.00%	$8.3437	0.00%
Baja to Off-System (Per Dth)	$6.0418	$9.2370	$6.0418	0.00%	$9.2370	0.00%
Silverado to Off-System (Per Dth)	$5.4576	$8.3437	$5.4576	0.00%	$8.3437	0.00%
Mission to Off-System (Per Dth)	$5.4576	$8.3437	$5.4576	0.00%	$8.3437	0.00%
	Usage Rate		Usage Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to Off-System (Per Dth)	$0.1032	0.0083	$0.1032	0.00%	0.0083	0.00%
Baja to Off-System (Per Dth)	$0.1140	0.0089	$0.1140	0.00%	0.0089	0.00%
Silverado to Off-System (Per Dth)	$0.1032	0.0083	$0.1032	0.00%	0.0083	0.00%
Mission to Off-System (Per Dth)	$0.1032	0.0083	$0.1032	0.00%	0.0083	0.00%
Gas Schedule G-BAL						
Self-Balancing Credit Paragraph Section	$0.0131		$0.0131	0.00%		
Gas Schedule G-CFS						
Reservation Charge per Dth per month	$0.1248		$0.1248	0.00%		
Gas Schedule G-LEND						
Minumum Rate (per transaction)	$57.00		$57.00	0.00%		
Maximum Rate (per Dth per day)	$1.1136		$1.1136	0.00%		
Gas Schedule G-NAS						
Injection Maximum Rates (Per Dth/Day)	$6.1542		$6.1542	0.00%		
Withdrawl Maximum Rates (Per Dth/Day)	$21.3075		$21.3075	0.00%		
Gas Schedule G-NFS						
Injection Maximum Rates (Per Dth/Day)	$6.1542		$6.1542	0.00%		
Inventory (Per Dth)	$2.9407		$2.9407	0.00%		
Withdrawl Maximum Rates (Per Dth/Day)	$21.3075		$21.3075	0.00%		
Gas Schedule G-PARK						
Minumum Rate (per transaction)	$57.00		$57.00	0.00%		
Maximum Rate (per Dth per day)	$1.1136		$1.1136	0.00%		
Gas Schedule G-SFS						
Reservation Charge per Dth per month	$0.2451		$0.2451	0.00%		
Gas Schedule G-SFT						
	Reservation Rate		Reservation Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to On-System (Per Dth)	$6.54910	$10.01250	$6.54910	0.00%	$10.01250	0.00%
Baja to On-System (Per Dth)	$7.25020	$11.08430	$7.25020	0.00%	$11.08430	0.00%
Baja to On-System Core Procurement Groups Only (Per Dth)	$6.34600	$8.82040	$6.34600	0.00%	$8.82040	0.00%
Silverado to On-System (Per Dth)	$3.79670	$5.56950	$3.79670	0.00%	$5.56950	0.00%
Mission to On-System (Per Dth)	$3.79670	$5.56950	$3.79670	0.00%	$5.56950	0.00%
	Usage Rate		Usage Rate			
Path	MFV Rates	SFV Rates	MFV Rates		SFV Rates	
Redwood to On-System (Per Dth)	$0.1238	$0.0100	$0.1238	0.00%	$0.0100	0.00%
Baja to On-System (Per Dth)	$0.1368	$0.0107	$0.1368	0.00%	$0.0107	0.00%
Baja to On-System Core Procurement Groups Only (Per Dth)	$0.0941	$0.0127	$0.0941	0.00%	$0.0127	0.00%
Silverado to On-System (Per Dth)	$0.0654	$0.0071	$0.0654	0.00%	$0.0071	0.00%
Mission to On-System (Per Dth)	$0.0654	$0.0071	$0.0654	0.00%	$0.0071	0.00%
Gas Schedule G-XF						
SFV Reservation Rates (Per Dth Per Month)	6.2159		6.2159	0.00%		
SFV Usage Rates Rates (Per Dth)	0.0015		0.0015	0.00%		

Notes:

1) Rates are based on 1/1/2012 implementation of the Annual Gas True-Up AL 3257-G-A for noncore and AL 3267-G for core

Comparison of Transportation Rate Changes

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Rate Schedules	1/1/2012 (1)	Average Rate No PPP	4/1/2012 (2)	% Chg from Jan 1, 2012	Average Rate No PPP	% Chg from Jan 2012

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

RESIDENTIAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-1			1
2	MINIMUM BILL ($/MONTH)	$4.50	$4.50	2
3	ES UNIT DISCOUNT ($/UNIT/MONTH)	($0.70)	($0.70)	3
4	ET UNIT DISCOUNT ($/UNIT/MONTH)	$2.35	$2.35	4
5	ES/ET MINIMUM RATE LIMITER ($/KWH)	$0.04892	$0.04892	5
6	ENERGY ($/KWH)			6
7	TIER 1	$0.12845	$0.12845	7
8	TIER 2	$0.14602	$0.14602	8
9	TIER 3	$0.29940	$0.29940	9
10	TIER 4	$0.33940	$0.33940	10
11	TIER 5	$0.33940	$0.33940	11
12	SCHEDULE EL-1 (CARE)			12
13	MINIMUM BILL ($/MONTH)	$3.60	$3.60	13
14	ENERGY ($/KWH)			14
15	TIER 1	$0.08316	$0.08316	15
16	TIER 2	$0.09563	$0.09563	16
17	TIER 3	$0.12474	$0.12474	17

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

RESIDENTIAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-6 / EM-TOU			1
2	MINIMUM BILL ($/MONTH)	$4.50	$4.50	2
3	E-6 METER CHARGE ($/MONTH)	$7.70	$7.70	3
4	ON-PEAK ENERGY ($/KWH)			4
5	TIER 1	$0.27883		5
6	TIER 2	$0.29640		6
7	TIER 3	$0.45032		7
8	TIER 4	$0.49032		8
9	TIER 5	$0.49032		9
10	PART-PEAK ENERGY ($/KWH)			10
11	TIER 1	$0.17017	$0.11776	11
12	TIER 2	$0.18775	$0.13533	12
13	TIER 3	$0.34167	$0.28925	13
14	TIER 4	$0.38167	$0.32925	14
15	TIER 5	$0.38167	$0.32925	15
16	OFF-PEAK ENERGY ($/KWH)			16
17	TIER 1	$0.09781	$0.10189	17
18	TIER 2	$0.11538	$0.11947	18
19	TIER 3	$0.26930	$0.27339	19
20	TIER 4	$0.30930	$0.31339	20
21	TIER 5	$0.30930	$0.31339	21
22	SCHEDULE EL-6 / EML-TOU			22
23	MINIMUM BILL ($/MONTH)	$3.60	$3.60	23
24	EL-6 METER CHARGE($/MONTH)	$6.16	$6.16	24
25	ON-PEAK ENERGY ($/KWH)			25
26	TIER 1	$0.19655		26
27	TIER 2	$0.21008		27
28	TIER 3	$0.29483		28
29	PART-PEAK ENERGY ($/KWH)			29
30	TIER 1	$0.11451	$0.07494	30
31	TIER 2	$0.12804	$0.08845	31
32	TIER 3	$0.17177	$0.11241	32
33	OFF-PEAK ENERGY ($/KWH)			33
34	TIER 1	$0.05987	$0.06295	34
35	TIER 2	$0.07340	$0.07647	35
36	TIER 3	$0.08981	$0.09443	36

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

RESIDENTIAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-7			1
2	MINIMUM BILL ($/MONTH)	$4.50	$4.50	2
3	E-7 METER CHARGE ($/MONTH)	$3.51	$3.51	3
4	RATE W METER CHARGE ($/MONTH)	$1.17	$1.17	4
5	ON-PEAK ENERGY ($/KWH)			5
6	TIER 1	$0.31312	$0.11093	6
7	TIER 2	$0.33128	$0.12909	7
8	TIER 3	$0.48465	$0.28246	8
9	TIER 4	$0.52465	$0.32246	9
10	TIER 5	$0.52465	$0.32246	10
11	OFF-PEAK ENERGY ($/KWH)			11
12	TIER 1	$0.07921	$0.08262	12
13	TIER 2	$0.09737	$0.10078	13
14	TIER 3	$0.25074	$0.25415	14
15	TIER 4	$0.29074	$0.29415	15
16	TIER 5	$0.29074	$0.29415	16
17	SCHEDULE EL-7			17
18	MINIMUM BILL ($/MONTH)	$4.50	$4.50	18
19	EL-7 METER CHARGE($/MONTH)	$0.00	$0.00	19
20	ON-PEAK ENERGY ($/KWH)			20
21	TIER 1	$0.26813	$0.08913	21
22	TIER 2	$0.28372	$0.10472	22
23	TIER 3	$0.40220	$0.13370	23
24	OFF-PEAK ENERGY ($/KWH)			24
25	TIER 1	$0.06105	$0.06407	25
26	TIER 2	$0.07664	$0.07966	26
27	TIER 3	$0.09158	$0.09611	27
28	SCHEDULE E-8			28
29	CUSTOMER CHARGE ($/MONTH)	$12.53	$12.53	29
30	ENERGY ($/KWH)			30
31	TIER 1	$0.13270	$0.08497	31
32	TIER 2	$0.13270	$0.08497	32
33	TIER 3	$0.28607	$0.23834	33
34	TIER 4	$0.32607	$0.27834	34
35	TIER 5	$0.32607	$0.27834	35
36	SCHEDULE EL-8 (CARE)			36
37	CUSTOMER CHARGE ($/MONTH)	$10.02	$10.02	37
38	ENERGY CHARGE ($/KWH)			38
39	TIER 1	$0.08624	$0.05234	39
40	TIER 2	$0.08624	$0.05234	40
41	TIER 3	$0.12936	$0.07851	41

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

RESIDENTIAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-A7			1
2	MINIMUM BILL ($/MONTH)	$4.50	$4.50	2
3	E-A7 METER CHARGE ($/MONTH)	$3.51	$3.51	3
4	RATE Y METER CHARGE ($/MONTH)	$1.17	$1.17	4
5	ON-PEAK ENERGY ($/KWH)			5
6	TIER 1	$0.34574	$0.11004	6
7	TIER 2	$0.36390	$0.12819	7
8	TIER 3	$0.51727	$0.28157	8
9	TIER 4	$0.55727	$0.32157	9
10	TIER 5	$0.55727	$0.32157	10
11	OFF-PEAK ENERGY ($/KWH)			11
12	TIER 1	$0.07452	$0.08272	12
13	TIER 2	$0.09267	$0.10087	13
14	TIER 3	$0.24605	$0.25425	14
15	TIER 4	$0.28605	$0.29425	15
16	TIER 5	$0.28605	$0.29425	16
17	SCHEDULE EL-A7			17
18	MINIMUM BILL ($/MONTH)	$4.50	$4.50	18
19	EL-A7 METER CHARGE($/MONTH)	$0.00	$0.00	19
20	ON-PEAK ENERGY ($/KWH)			20
21	TIER 1	$0.29701	$0.08834	21
22	TIER 2	$0.31260	$0.10393	22
23	TIER 3	$0.44552	$0.13251	23
24	OFF-PEAK ENERGY ($/KWH)			24
25	TIER 1	$0.05689	$0.06415	25
26	TIER 2	$0.07248	$0.07974	26
27	TIER 3	$0.08534	$0.09623	27
28	SCHEDULE E-9: RATE A			28
29	MINIMUM BILL ($/MONTH)	$4.50	$4.50	29
30	E-9 METER CHARGE ($/MONTH)	$6.66	$6.66	30
31	ON-PEAK ENERGY ($/KWH)			31
32	TIER 1	$0.30178		32
33	TIER 2	$0.31994		33
34	TIER 3	$0.50415		34
35	TIER 4	$0.54415		35
36	TIER 5	$0.54415		36
37	PART-PEAK ENERGY ($/KWH)			37
38	TIER 1	$0.09876	$0.09864	38
39	TIER 2	$0.11692	$0.11679	39
40	TIER 3	$0.30113	$0.30101	40
41	TIER 4	$0.34113	$0.34101	41
42	TIER 5	$0.34113	$0.34101	42
43	OFF-PEAK ENERGY ($/KWH)			43
44	TIER 1	$0.03743	$0.04680	44
45	TIER 2	$0.05559	$0.06495	45
46	TIER 3	$0.16011	$0.16011	46
47	TIER 4	$0.20011	$0.20011	47
48	TIER 5	$0.20011	$0.20011	48

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
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RESIDENTIAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-9: RATE B			1
2	MINIMUM BILL ($/MONTH)	$4.50	$4.50	2
3	E-9 METER CHARGE ($/MONTH)	$6.66	$6.66	3
4	ON-PEAK ENERGY ($/KWH)			4
5	TIER 1	$0.29726		5
6	TIER 2	$0.31541		6
7	TIER 3	$0.49962		7
8	TIER 4	$0.53962		8
9	TIER 5	$0.53962		9
10	PART-PEAK ENERGY ($/KWH)			10
11	TIER 1	$0.09424	$0.09462	11
12	TIER 2	$0.11239	$0.11277	12
13	TIER 3	$0.29661	$0.29699	13
14	TIER 4	$0.33661	$0.33699	14
15	TIER 5	$0.33661	$0.33699	15
16	OFF-PEAK ENERGY ($/KWH)			16
17	TIER 1	$0.04479	$0.05339	17
18	TIER 2	$0.06295	$0.07155	18
19	TIER 3	$0.24716	$0.25576	19
20	TIER 4	$0.28716	$0.29576	20
21	TIER 5	$0.28716	$0.29576	21

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

SMALL L&P RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE A-1			1
2	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	2
3	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	3
4	ENERGY ($/KWH)	$0.20522	$0.14493	4
5	SCHEDULE A-1 TOU			5
6	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	6
7	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	7
8	ENERGY ($/KWH)			8
9	ON-PEAK	$0.21978		9
10	PART-PEAK	$0.21321	$0.15223	10
11	OFF-PEAK ENERGY	$0.19322	$0.13816	11
12	SCHEDULE A-6			12
13	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	13
14	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	14
15	METER CHARGE ($/MONTH)	$6.12	$6.12	15
16	METER CHARGE - RATE W ($/MONTH)	$1.80	$1.80	16
17	METER CHARGE - RATE X ($/MONTH)	$6.12	$6.12	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.43995		19
20	PART-PEAK	$0.22498	$0.15247	20
21	OFF-PEAK ENERGY	$0.13840	$0.12840	21
22	SCHEDULE A-15			22
23	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	23
24	FACILITY CHARGE ($/MONTH)	$25.00	$25.00	24
25	ENERGY ($/KWH)	$0.20522	$0.14493	25
26	SCHEDULE TC-1			26
27	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	27
28	ENERGY ($/KWH)	$0.14178	$0.14178	28

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

MEDIUM L&P RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE A-10			1
2	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MO)			3
4	SECONDARY VOLTAGE	$12.15	$5.63	4
5	PRIMARY VOLTAGE	$11.38	$5.84	5
6	TRANSMISSION VOLTAGE	$7.47	$4.13	6
7	ENERGY CHARGE ($/KWH)			7
8	SECONDARY VOLTAGE	$0.13834	$0.10331	8
9	PRIMARY VOLTAGE	$0.12944	$0.09904	9
10	TRANSMISSION VOLTAGE	$0.10537	$0.08669	10
11	SCHEDULE A-10 TOU			11
12	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	12
13	MAXIMUM DEMAND CHARGE ($/KW/MO)			13
14	SECONDARY VOLTAGE	$12.15	$5.63	14
15	PRIMARY VOLTAGE	$11.38	$5.84	15
16	TRANSMISSION VOLTAGE	$7.47	$4.13	16
17	ENERGY CHARGE ($/KWH)			17
18	SECONDARY			18
19	ON PEAK	$0.15130		19
20	PARTIAL PEAK	$0.14543	$0.11116	20
21	OFF-PEAK	$0.12759	$0.09586	21
22	PRIMARY			22
23	ON PEAK	$0.14026		23
24	PARTIAL PEAK	$0.13607	$0.10545	24
25	OFF-PEAK	$0.12008	$0.09293	25
26	TRANSMISSION			26
27	ON PEAK	$0.11521		27
28	PARTIAL PEAK	$0.11139	$0.09260	28
29	OFF-PEAK	$0.09686	$0.08108	29

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
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E-19 FIRM RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-19 T FIRM			1
2	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,800.00	$1,800.00	2
3	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	3
4	TOU METER CHARGE - RATES V & X ($/MONTH)	$5.40	$5.40	4
5	TOU METER CHARGE - RATE W ($/MONTH)	$1.08	$1.08	5
6	DEMAND CHARGE ($/KW/MONTH)			6
7	ON-PEAK	$12.37		7
8	PARTIAL PEAK	$2.74	$0.00	8
9	MAXIMUM	$5.35	$5.35	9
10	ENERGY CHARGE ($/KWH)			10
11	ON-PEAK	$0.08241		11
12	PARTIAL-PEAK	$0.07903	$0.07784	12
13	OFF-PEAK	$0.06725	$0.06850	13
14	SCHEDULE E-19 P FIRM			14
15	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,000.00	$1,000.00	15
16	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	16
17	TOU METER CHARGE - RATES V & X ($/MONTH)	$5.40	$5.40	17
18	TOU METER CHARGE - RATE W ($/MONTH)	$1.08	$1.08	18
19	DEMAND CHARGE ($/KW/MONTH)			19
20	ON-PEAK	$14.48		20
21	PARTIAL PEAK	$3.15	$0.40	21
22	MAXIMUM	$9.23	$9.23	22
23	ENERGY CHARGE ($/KWH)			23
24	ON-PEAK	$0.12433		24
25	PARTIAL-PEAK	$0.09053	$0.08671	25
26	OFF-PEAK	$0.07039	$0.07280	26
27	SCHEDULE E-19 S FIRM			27
28	CUSTOMER CHARGE > 500 KW ($/MONTH)	$600.00	$600.00	28
29	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	29
30	TOU METER CHARGE - RATES V & X ($/MONTH)	$5.40	$5.40	30
31	TOU METER CHARGE - RATE W ($/MONTH)	$1.08	$1.08	31
32	DEMAND CHARGE ($/KW/MONTH)			32
33	ON-PEAK	$14.70		33
34	PARTIAL PEAK	$3.43	$0.21	34
35	MAXIMUM	$11.85	$11.85	35
36	ENERGY CHARGE ($/KWH)			36
37	ON-PEAK	$0.13476		37
38	PARTIAL-PEAK	$0.09579	$0.09063	38
39	OFF-PEAK	$0.07028	$0.07320	39

PACIFIC GAS AND ELECTRIC COMPANY
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E-20 FIRM RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-20 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)-FIRM	$2,000.00	$2,000.00	2
3	DEMAND CHARGE ($/KW/MONTH)			3
4	ON-PEAK	$12.24		4
5	PARTIAL PEAK	$2.65	$0.00	5
6	MAXIMUM	$4.06	$4.06	6
7	ENERGY CHARGE ($/KWH)			7
8	ON-PEAK	$0.08981		8
9	PARTIAL-PEAK	$0.07574	$0.07680	9
10	OFF-PEAK	$0.06397	$0.06704	10
11	SCHEDULE E-20 P FIRM			11
12	CUSTOMER CHARGE ($/MONTH)	$1,500.00	$1,500.00	12
13	DEMAND CHARGE ($/KW/MONTH)			13
14	ON-PEAK	$14.03		14
15	PARTIAL PEAK	$2.99	$0.25	15
16	MAXIMUM	$9.36	$9.36	16
17	ENERGY CHARGE ($/KWH)			17
18	ON-PEAK	$0.12350		18
19	PARTIAL-PEAK	$0.09010	$0.08633	19
20	OFF-PEAK	$0.07057	$0.07360	20
21	SCHEDULE E-20 S FIRM			21
22	CUSTOMER CHARGE ($/MONTH)	$1,000.00	$1,000.00	22
23	DEMAND CHARGE ($/KW/MONTH)			23
24	ON-PEAK	$14.32		24
25	PARTIAL PEAK	$3.15	$0.23	25
26	MAXIMUM	$11.72	$11.72	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.12421		28
29	PARTIAL-PEAK	$0.09141	$0.08675	29
30	OFF-PEAK	$0.06979	$0.07066	30

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

OIL AND GAS EXTRACTION RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE E-37			1
2	CUSTOMER CHARGE ($/MONTH)	$36.00	$36.00	2
3	TOU METER CHARGE - RATE W ($/MONTH)	$1.20	$1.20	3
4	TOU METER CHARGE - RATE X ($/MONTH)	$6.00	$6.00	4
5	ON PEAK DEMAND CHARGE ($/KW/MO)	$7.49		5
6	MAXIMUM DEMAND CHARGE ($/KW/MO)			6
7	SECONDARY VOLTAGE	$11.83	$4.65	7
8	PRIMARY VOLTAGE DISCOUNT	$1.29	$0.15	8
9	TRANSMISSION VOLTAGE DISCOUNT	$8.88	$4.00	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.16343		11
12	PART-PEAK		$0.08843	12
13	OFF-PEAK	$0.07318	$0.06687	13

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
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STANDBY RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE S - TRANSMISSION			1
2	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$0.92	$0.92	2
3	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$0.78	$0.78	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.09595		5
6	PART-PEAK	$0.09236	$0.09098	6
7	OFF-PEAK	$0.07871	$0.08015	7
8	SCHEDULE S - PRIMARY			8
9	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$3.03	$3.03	9
10	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$2.58	$2.58	10
11	ENERGY ($/KWH)			11
12	ON-PEAK	$0.45501		12
13	PART-PEAK	$0.24566	$0.13015	13
14	OFF-PEAK	$0.16041	$0.10919	14
15	SCHEDULE S - SECONDARY			15
16	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$3.05	$3.05	16
17	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$2.59	$2.59	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.45316		19
20	PART-PEAK	$0.24402	$0.13053	20
21	OFF-PEAK	$0.15874	$0.10790	21

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

STANDBY RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE S CUSTOMER AND METER CHARGES			1
2	RESIDENTIAL			2
3	CUSTOMER CHARGE ($/MO)	$5.00	$5.00	3
4	TOU METER CHARGE ($/MO)	$3.90	$3.90	4
5	AGRICULTURAL			5
6	CUSTOMER CHARGE ($/MO)	$16.00	$16.00	6
7	TOU METER CHARGE ($/MO)	$6.00	$6.00	7
8	SMALL LIGHT AND POWER (less than or equal to 50 kW)			8
9	SINGLE PHASE CUSTOMER CHARGE ($/MO)	$10.00	$10.00	9
10	POLY PHASE CUSTOMER CHARGE ($/MO)	$20.00	$20.00	10
11	METER CHARGE ($/MO)	$6.12	$6.12	11
12	MEDIUM LIGHT AND POWER (>50 kW, <500 kW)			12
13	CUSTOMER CHARGE ($/MO)	$140.00	$140.00	13
14	METER CHARGE ($/MO)	$5.40	$5.40	14
15	MEDIUM LIGHT AND POWER (>500kW)			15
16	TRANSMISSION CUSTOMER CHARGE ($/MO)	$1,800.00	$1,800.00	16
17	PRIMARY CUSTOMER CHARGE ($/MO)	$1,000.00	$1,000.00	17
18	SECONDARY CUSTOMER CHARGE ($/MO)	$600.00	$600.00	18
19	LARGE LIGHT AND POWER (> 1000 kW)			19
20	TRANSMISSION CUSTOMER CHARGE ($/MO)	$2,000.00	$2,000.00	20
21	PRIMARY CUSTOMER CHARGE ($/MO)	$1,500.00	$1,500.00	21
22	SECONDARY CUSTOMER CHARGE ($/MO)	$1,000.00	$1,000.00	22
23	REDUCED CUSTOMER CHARGES ($/MO)			23
24	SMALL LIGHT AND PWR ((` < 50 kW)	$14.31	$14.31	24
25	MED LIGHT AND PWR (Res Capacity >50 kW and <500 kW)	$74.87	$74.87	25
26	MED LIGHT AND PWR (Res Capacity > 500 kW and < 1000 kW)	$1,206.88	$1,206.88	26

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
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AGRICULTURAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE AG-1A			1
2	CUSTOMER CHARGE ($/MONTH)	$17.30	$17.30	2
3	CONNECTED LOAD CHARGE ($/KW/MONTH)	$6.09	$1.17	3
4	ENERGY CHARGE ($/KWH)	$0.21678	$0.17016	4
5	SCHEDULE AG-RA			5
6	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.30	$17.30	6
7	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	7
8	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	8
9	CONNECTED LOAD CHARGE ($/KW/MONTH)	$5.44	$0.89	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.40498		11
12	PART-PEAK		$0.14871	12
13	OFF-PEAK	$0.14624	$0.12288	13
14	SCHEDULE AG-VA			14
15	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.30	$17.30	15
16	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	16
17	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	17
18	CONNECTED LOAD CHARGE ($/KW/MONTH)	$5.46	$0.93	18
19	ENERGY ($/KWH)			19
20	ON-PEAK	$0.37867		20
21	PART-PEAK		$0.14941	21
22	OFF-PEAK	$0.14330	$0.12353	22
23	SCHEDULE AG-4A			23
24	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.30	$17.30	24
25	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	25
26	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	26
27	CONNECTED LOAD CHARGE ($/KW/MONTH)	$5.42	$0.80	27
28	ENERGY ($/KWH)			28
29	ON-PEAK	$0.31325		29
30	PART-PEAK		$0.14856	30
31	OFF-PEAK	$0.14372	$0.12305	31
32	SCHEDULE AG-5A			32
33	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.30	$17.30	33
34	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	34
35	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	35
36	CONNECTED LOAD CHARGE ($/KW/MONTH)	$8.77	$1.63	36
37	ENERGY ($/KWH)			37
38	ON-PEAK	$0.23588		38
39	PART-PEAK		$0.12902	39
40	OFF-PEAK	$0.12275	$0.10987	40

PACIFIC GAS AND ELECTRIC COMPANY
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AGRICULTURAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE AG-1B			1
2	CUSTOMER CHARGE ($/MONTH)	$23.00	$23.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			3
4	SECONDARY VOLTAGE	$9.08	$1.86	4
5	PRIMARY VOLTAGE DISCOUNT	$0.94	$0.25	5
6	ENERGY CHARGE ($/KWH)	$0.18725	$0.14738	6
7	SCHEDULE AG-RB			7
8	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.00	$23.00	8
9	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	9
10	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	10
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.83		11
12	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			12
13	SECONDARY VOLTAGE	$7.48	$1.54	13
14	PRIMARY VOLTAGE DISCOUNT	$0.62	$0.24	14
15	ENERGY CHARGE ($/KWH)			15
16	ON-PEAK	$0.36570		16
17	PART-PEAK		$0.12858	17
18	OFF-PEAK	$0.13657	$0.10878	18
19	SCHEDULE AG-VB			19
20	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.00	$23.00	20
21	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	21
22	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	22
23	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.80		23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			24
25	SECONDARY VOLTAGE	$7.54	$1.52	25
26	PRIMARY VOLTAGE DISCOUNT	$0.67	$0.23	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.33815		28
29	PART-PEAK		$0.12708	29
30	OFF-PEAK	$0.13325	$0.10752	30

PACIFIC GAS AND ELECTRIC COMPANY
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AGRICULTURAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE AG-4B			1
2	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.00	$23.00	2
3	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$3.82		5
6	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			6
7	SECONDARY VOLTAGE	$7.19	$1.66	7
8	PRIMARY VOLTAGE DISCOUNT	$0.76	$0.25	8
9	ENERGY CHARGE ($/KWH)			9
10	ON-PEAK	$0.21989		10
11	PART-PEAK		$0.12239	11
12	OFF-PEAK	$0.12222	$0.10431	12
13	SCHEDULE AG-4C			13
14	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$64.80	$64.80	14
15	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	15
16	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	16
17	DEMAND CHARGE ($/KW/MONTH)			17
18	ON-PEAK	$9.12		18
19	PART-PEAK	$1.75	$0.42	19
20	MAXIMUM	$3.79	$1.84	20
21	PRIMARY VOLTAGE DISCOUNT	$1.00	$0.23	21
22	TRANSMISSION VOLTAGE DISCOUNT			22
23	ON-PEAK	$4.79		23
24	PART-PEAK	$0.99	$0.42	24
25	MAXIMUM	$0.18	$1.28	25
26	ENERGY CHARGE ($/KWH)			26
27	ON-PEAK	$0.20361		27
28	PART-PEAK	$0.12259	$0.10352	28
29	OFF-PEAK	$0.09423	$0.09090	29
30	SCHEDULE AG-5B			30
31	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$36.00	$36.00	31
32	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	32
33	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	33
34	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.49		34
35	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			35
36	SECONDARY VOLTAGE	$11.83	$4.65	36
37	PRIMARY VOLTAGE DISCOUNT	$1.29	$0.15	37
38	TRANSMISSION VOLTAGE DISCOUNT	$8.88	$4.00	38
39	ENERGY CHARGE ($/KWH)			39
40	ON-PEAK	$0.16343		40
41	PART-PEAK		$0.08843	41
42	OFF-PEAK	$0.07318	$0.06687	42

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

AGRICULTURAL RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE AG-5C			1
2	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$160.00	$160.00	2
3	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	4
5	DEMAND CHARGE ($/KW/MONTH)			5
6	ON-PEAK	$12.61		6
7	PART-PEAK	$2.63	$0.68	7
8	MAXIMUM	$4.58	$2.86	8
9	PRIMARY VOLTAGE DISCOUNT	$1.86	$0.19	9
10	TRANSMISSION VOLTAGE DISCOUNT			10
11	ON-PEAK	$7.90		11
12	PART-PEAK	$1.19	$0.68	12
13	MAXIMUM	$2.60	$1.88	13
14	ENERGY CHARGE ($/KWH)			14
15	ON-PEAK	$0.12605		15
16	PART-PEAK	$0.08792	$0.07798	16
17	OFF-PEAK	$0.07372	$0.07152	17
18	SCHEDULE AG-ICE			18
19	CUSTOMER CHARGE ($/MONTH)	$40.00	$40.00	19
20	METER CHARGE ($/MONTH)	$6.00	$6.00	20
21	ON-PEAK DEMAND CHARGE ($/KW/MO)	$2.95		21
22	MAXIMUM DEMAND CHARGE ($/KW/MO)			22
23	SECONDARY	$3.80	$0.00	23
24	PRIMARY	$3.19	$0.00	24
25	TRANSMISSION	$1.77	$0.00	25
26	ENERGY CHARGE ($/KWH)			26
27	ON-PEAK	$0.12059		27
28	PART-PEAK	$0.09405	$0.09647	28
29	OFF-PEAK	$0.04823	$0.04823	29

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012

STREETLIGHTING RATES

LINE NO.		3/1/12 RATES SUMMER	3/1/12 RATES WINTER	LINE NO.
1	SCHEDULE LS-1			1
2	ENERGY CHARGE ($/KWH)	$0.12792	$0.12792	2
3	SCHEDULE LS-2			3
4	ENERGY CHARGE ($/KWH)	$0.12792	$0.12792	4
5	SCHEDULE LS-3			5
6	SERVICE CHARGE ($/METER/MO.)	$6.00	$6.00	6
7	ENERGY CHARGE ($/KWH)	$0.12792	$0.12792	7
8	SCHEDULE OL-1			8
9	ENERGY CHARGE ($/KWH)	$0.13703	$0.13703	9

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012
ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
LAMP WATTS	AVERAGE kWhr PER MONTH	INITIAL LUMENS	SCHEDULE LS-2 A	SCHEDULE LS-2 C	SCHEDULE LS-1 A	SCHEDULE LS-1 B	SCHEDULE LS-1 C	SCHEDULE LS-1 D	SCHEDULE LS-1 E	SCHEDULE LS-1 F	OL-1	LS-1 & LS-2	OL-1
MERCURY VAPOR LAMPS													
40	18	1,300	$2.509	--	--	--	--	--	--	--	--	$0.105	--
50	22	1,650	$3.020	--	--	--	--	--	--	--	--	$0.128	--
100	40	3,500	$5.323	$7.499	$11.487	--	$9.760	--	--	--	--	$0.233	--
175	68	7,500	$8.905	$11.081	$15.069	$13.271	$13.342	--	$15.554	$16.608	$15.688	$0.395	$0.424
250	97	11,000	$12.614	$14.790	$18.778	$16.980	$17.051	--	--	--	--	$0.564	--
400	152	21,000	$19.650	$21.826	$25.814	$24.016	$24.087	--	--	--	$27.199	$0.884	$0.947
700	266	37,000	$34.233	$36.409	$40.397	$38.599	$38.670	--	--	--	--	$1.547	--
1,000	377	57,000	$48.432	$50.608	--	--	--	--	--	--	--	$2.192	--
INCANDESCENT LAMPS													
58	20	600	$2.764	--	$8.928	--	--	--	--	--	--	$0.116	--
92	31	1,000	$4.172	$6.348	$10.336	--	--	--	--	--	--	$0.180	--
189	65	2,500	$8.521	$10.697	$14.685	$12.887	--	--	--	--	--	$0.378	--
295	101	4,000	$13.126	$15.302	$19.290	$17.492	--	--	--	--	--	$0.587	--
405	139	6,000	$17.987	$20.163	$24.151	--	--	--	--	--	--	$0.808	--
620	212	10,000	$27.325	$29.501	--	--	--	--	--	--	--	$1.233	--
860	294	15,000	$37.814	--	--	--	--	--	--	--	--	$1.709	--
LOW PRESSURE SODIUM VAPOR LAMPS													
35	21	4,800	$2.892	--	--	--	--	--	--	--	--	$0.122	--
55	29	8,000	$3.916	--	--	--	--	--	--	--	--	$0.169	--
90	45	13,500	$5.962	--	--	--	--	--	--	--	--	$0.262	--
135	62	21,500	$8.137	--	--	--	--	--	--	--	--	$0.361	--
180	78	33,000	$10.184	--	--	--	--	--	--	--	--	$0.454	--

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF MARCH 1, 2012
ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
	AVERAGE		SCHEDULE LS-2		SCHEDULE LS-1							LS-1 &	
LAMP WATTS	kWhr PER MONTH	INITIAL LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-2	OL-1
HIGH PRESSURE SODIUM VAPOR LAMPS AT 120 VOLTS													
35	15	2,150	$2.125	--	--	--	--	--	--	--	--	$0.087	--
50	21	3,800	$2.892	--	--	--	--	--	--	--	--	$0.122	--
70	29	5,800	$3.916	$6.092	$10.080	--	$8.353	$10.953	$10.565	$11.619	$10.344	$0.169	$0.181
100	41	9,500	$5.451	$7.627	$11.615	--	$9.888	$12.488	$12.100	$13.154	$11.988	$0.238	$0.255
150	60	16,000	$7.881	$10.057	$14.045	--	$12.318	$14.918	$14.530	$15.584	--	$0.349	--
200	80	22,000	$10.440	--	$16.604	--	$14.877	$17.477	$17.089	$18.143	--	$0.465	--
250	100	26,000	$12.998	--	$19.162	--	$17.435	$20.035	$19.647	$20.701	--	$0.581	--
400	154	46,000	$19.906	--	$26.070	--	$24.343	$26.943	$26.555	$27.609	--	$0.895	--
AT 240 VOLTS													
50	24	3,800	$3.276	--	--	--	--	--	--	--	--	$0.140	--
70	34	5,800	$4.555	$6.731	$10.719	--	--	--	--	--	--	$0.198	--
100	47	9,500	$6.218	$8.394	$12.382	--	$10.655	--	$12.867	$13.921	--	$0.273	--
150	69	16,000	$9.032	$11.208	$15.196	--	$13.469	--	$15.681	$16.735	--	$0.401	--
200	81	22,000	$10.568	$12.744	$16.732	--	$15.005	--	$17.217	$18.271	$17.469	$0.471	$0.505
250	100	25,500	$12.998	$15.174	$19.162	--	$17.435	--	$19.647	$20.701	$20.073	$0.581	$0.623
310	119	37,000	$15.428	--	--	--	--	--	--	--	--	$0.692	--
360	144	45,000	$18.626	--	--	--	--	--	--	--	--	$0.837	--
400	154	46,000	$19.906	$22.082	$26.070	--	$24.343	--	$26.555	$27.609	$27.473	$0.895	$0.959
METAL HALIDE LAMPS													
70	30	5,500	$4.044	--	--	--	--	--	--	--	--	$0.174	--
100	41	8,500	$5.451	--	--	--	--	--	--	--	--	$0.238	--
150	63	13,500	$8.265	--	--	--	--	--	--	--	--	$0.366	--
175	72	14,000	$9.416	--	--	--	--	--	--	--	--	$0.419	--
250	105	20,500	$13.638	--	--	--	--	--	--	--	--	$0.611	--
400	162	30,000	$20.929	--	--	--	--	--	--	--	--	$0.942	--
1,000	387	90,000	$49.711	--	--	--	--	--	--	--	--	$2.250	--
INDUCTION LAMPS													
23	9	1,840	$1.357									$0.052	
35	13	2,450	$1.869									$0.076	
40	14	2,200	$1.997	--	--	--	--	--	--	--	--	$0.081	--
50	18	3,500	$2.509									$0.105	
55	19	3,000	$2.636	--	--	--	--	--	--	--	--	$0.110	--
65	24	5,525	$3.276									$0.140	
70	27	6,500	$3.660									$0.157	
80	28	4,500	$3.788	--	--	--	--	--	--	--	--	$0.163	--
85	30	4,800	$4.044	--	--	--	--	--	--	--	--	$0.174	--
100	36	8,000	$4.811									$0.209	
120	42	8,500	$5.516	--	--	--	--	--	--	--	--	$0.241	--
135	48	9,450	$6.346									$0.279	
150	51	10,900	$6.730	--	--	--	--	--	--	--	--	$0.297	--
165	58	12,000	$7.625	--	--	--	--	--	--	--	--	$0.337	--
200	72	19,000	$9.416									$0.419	

Energy Rate @ $0.12792 per kwh LS-1 & LS-2
$0.13703 per kwh OL-1

Pole Painting Charge @ $0.000 Per Pole Per Month

PACIFIC GAS AND ELECTRIC COMPANY
AS OF MARCH 1, 2012

PRESENT ELECTRIC RATES FOR LIGHT EMITTING DIODE (LED) LAMPS

NOMINAL LAMP RATINGS Lamp Watts	Average kWh Per Month	ALL NIGHT RATES PER LAMP PER MONTH LS-2A	HALF-HOUR ADJUSTMENT LS-1A, C, E, F & LS-2A	ALL NIGHT RATES PER LAMP PER MONTH LS-1A	LS-1C	LS-1E	LS-1F
0.0-5.0	0.9	$0.321	$0.005	$6.485	$4.758	$6.970	$8.024
5.1-10.0	2.6	$0.539	$0.015	$6.703	$4.976	$7.188	$8.242
10.1-15.0	4.3	$0.756	$0.025	$6.920	$5.193	$7.405	$8.459
15.1-20.0	6.0	$0.974	$0.035	$7.138	$5.411	$7.623	$8.677
20.1-25.0	7.7	$1.191	$0.045	$7.355	$5.628	$7.840	$8.894
25.1-30.0	9.4	$1.408	$0.055	$7.572	$5.845	$8.057	$9.111
30.1-35.0	11.1	$1.626	$0.065	$7.790	$6.063	$8.275	$9.329
35.1-.40.0	12.8	$1.843	$0.074	$8.007	$6.280	$8.492	$9.546
40.1-45.0	14.5	$2.061	$0.084	$8.225	$6.498	$8.710	$9.764
45.1-50.0	16.2	$2.278	$0.094	$8.442	$6.715	$8.927	$9.981
50.1-55.0	17.9	$2.496	$0.104	$8.660	$6.933	$9.145	$10.199
55.1-60.0	19.6	$2.713	$0.114	$8.877	$7.150	$9.362	$10.416
60.1-65.0	21.4	$2.943	$0.124	$9.107	$7.380	$9.592	$10.646
65.1-70.0	23.1	$3.161	$0.134	$9.325	$7.598	$9.810	$10.864
70.1-75.0	24.8	$3.378	$0.144	$9.542	$7.815	$10.027	$11.081
75.1-80.0	26.5	$3.596	$0.154	$9.760	$8.033	$10.245	$11.299
80.1-85.0	28.2	$3.813	$0.164	$9.977	$8.250	$10.462	$11.516
85.1-90.0	29.9	$4.031	$0.174	$10.195	$8.468	$10.680	$11.734
90.1-95.0	31.6	$4.248	$0.184	$10.412	$8.685	$10.897	$11.951
95.1-100.0	33.3	$4.466	$0.194	$10.630	$8.903	$11.115	$12.169
100.1-105.1	35.0	$4.683	$0.204	$10.847	$9.120	$11.332	$12.386
105.1-110.0	36.7	$4.901	$0.213	$11.065	$9.338	$11.550	$12.604
110.1-115.0	38.4	$5.118	$0.223	$11.282	$9.555	$11.767	$12.821
115.1-120.0	40.1	$5.336	$0.233	$11.500	$9.773	$11.985	$13.039
120.1-125.0	41.9	$5.566	$0.244	$11.730	$10.003	$12.215	$13.269
125.1-130.0	43.6	$5.783	$0.254	$11.947	$10.220	$12.432	$13.486
130.1-135.0	45.3	$6.001	$0.263	$12.165	$10.438	$12.650	$13.704
135.1-140.0	47.0	$6.218	$0.273	$12.382	$10.655	$12.867	$13.921
140.1-145.0	48.7	$6.436	$0.283	$12.600	$10.873	$13.085	$14.139
145.1-150.0	50.4	$6.653	$0.293	$12.817	$11.090	$13.302	$14.356
150.1-155.0	52.1	$6.871	$0.303	$13.035	$11.308	$13.520	$14.574
155.1-160.0	53.8	$7.088	$0.313	$13.252	$11.525	$13.737	$14.791
160.1-165.0	55.5	$7.306	$0.323	$13.470	$11.743	$13.955	$15.009
165.1-170.0	57.2	$7.523	$0.333	$13.687	$11.960	$14.172	$15.226
170.1-175.0	58.9	$7.740	$0.342	$13.904	$12.177	$14.389	$15.443
175.1-180.0	60.6	$7.958	$0.352	$14.122	$12.395	$14.607	$15.661
180.1-185.0	62.4	$8.188	$0.363	$14.352	$12.625	$14.837	$15.891
185.1-190.0	64.1	$8.406	$0.373	$14.570	$12.843	$15.055	$16.109
190.1-195.0	65.8	$8.623	$0.383	$14.787	$13.060	$15.272	$16.326

PACIFIC GAS AND ELECTRIC COMPANY
AS OF MARCH 1, 2012

PRESENT ELECTRIC RATES FOR LIGHT EMITTING DIODE (LED) LAMPS

NOMINAL LAMP RATINGS		ALL NIGHT RATES PER LAMP PER MONTH	HALF-HOUR ADJUSTMENT	ALL NIGHT RATES PER LAMP PER MONTH			
Lamp Watts	Average kWh Per Month	LS-2A	LS-1A, C, E, F & LS-2A	LS-1A	LS-1C	LS-1E	LS-1F
195.1-200.0	67.5	$8.841	$0.393	$15.005	$13.278	$15.490	$16.544
200.1-205.0	69.2	$9.058	$0.402	$15.222	$13.495	$15.707	$16.761
205.1-210.0	70.9	$9.276	$0.412	$15.440	$13.713	$15.925	$16.979
210.1-215.0	72.6	$9.493	$0.422	$15.657	$13.930	$16.142	$17.196
215.1-220.0	74.3	$9.710	$0.432	$15.874	$14.147	$16.359	$17.413
220.1-225.0	76.0	$9.928	$0.442	$16.092	$14.365	$16.577	$17.631
225.1-230.0	77.7	$10.145	$0.452	$16.309	$14.582	$16.794	$17.848
230.1-235.0	79.4	$10.363	$0.462	$16.527	$14.800	$17.012	$18.066
235.1-240.0	81.1	$10.580	$0.472	$16.744	$15.017	$17.229	$18.283
240.1-245.0	82.9	$10.811	$0.482	$16.975	$15.248	$17.460	$18.514
245.1-250.0	84.6	$11.028	$0.492	$17.192	$15.465	$17.677	$18.731
250.1-255.0	86.3	$11.245	$0.502	$17.409	$15.682	$17.894	$18.948
255.1-260.0	88.0	$11.463	$0.512	$17.627	$15.900	$18.112	$19.166
260.1-265.0	89.7	$11.680	$0.522	$17.844	$16.117	$18.329	$19.383
265.1-270.0	91.4	$11.898	$0.531	$18.062	$16.335	$18.547	$19.601
270.1-275.0	93.1	$12.115	$0.541	$18.279	$16.552	$18.764	$19.818
275.1-280.0	94.8	$12.333	$0.551	$18.497	$16.770	$18.982	$20.036
280.1-285.0	96.5	$12.550	$0.561	$18.714	$16.987	$19.199	$20.253
285.1-290.0	98.2	$12.768	$0.571	$18.932	$17.205	$19.417	$20.471
290.1-295.0	99.9	$12.985	$0.581	$19.149	$17.422	$19.634	$20.688
295.1-300.0	101.6	$13.203	$0.591	$19.367	$17.640	$19.852	$20.906
300.1-305.0	103.4	$13.433	$0.601	$19.597	$17.870	$20.082	$21.136
305.1-310.0	105.1	$13.650	$0.611	$19.814	$18.087	$20.299	$21.353
310.1-315.0	106.8	$13.868	$0.621	$20.032	$18.305	$20.517	$21.571
315.1-320.0	108.5	$14.085	$0.631	$20.249	$18.522	$20.734	$21.788
320.1-325.0	110.2	$14.303	$0.641	$20.467	$18.740	$20.952	$22.006
325.1-330.0	111.9	$14.520	$0.651	$20.684	$18.957	$21.169	$22.223
330.1-335.0	113.6	$14.738	$0.661	$20.902	$19.175	$21.387	$22.441
335.1-340.0	115.3	$14.955	$0.670	$21.119	$19.392	$21.604	$22.658
340.1-345.0	117.0	$15.173	$0.680	$21.337	$19.610	$21.822	$22.876
345.1-350.0	118.7	$15.390	$0.690	$21.554	$19.827	$22.039	$23.093
350.1-355.0	120.4	$15.608	$0.700	$21.772	$20.045	$22.257	$23.311
355.1-360.0	122.1	$15.825	$0.710	$21.989	$20.262	$22.474	$23.528
360.1-365.0	123.9	$16.055	$0.720	$22.219	$20.492	$22.704	$23.758
365.1-370.0	125.6	$16.273	$0.730	$22.437	$20.710	$22.922	$23.976
370.1-375.0	127.3	$16.490	$0.740	$22.654	$20.927	$23.139	$24.193
375.1-380.0	129.0	$16.708	$0.750	$22.872	$21.145	$23.357	$24.411
380.1-385.0	130.7	$16.925	$0.760	$23.089	$21.362	$23.574	$24.628
385.1-390.0	132.4	$17.143	$0.770	$23.307	$21.580	$23.792	$24.846
390.1-395.0	134.1	$17.360	$0.780	$23.524	$21.797	$24.009	$25.063
395.1-400.0	135.8	$17.578	$0.790	$23.742	$22.015	$24.227	$25.281

Exhibit C

Statement of Proposed Changes

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT C
ELECTRIC DEPARTMENT
SUMMARY OF REVENUES BY CUSTOMER CLASS

Line No.	Customer Class	Total Revenue at March 1, 2012 Rates (000's)	Proposed Illustrative Class Revenue (000's)	Revenue Change (000's)	Percentage Change	Line No.
	Bundled Service*					
1	Residential	$5,152,860	$5,475,133	$322,272	6.3%	1
2	Small Light and Power	$1,470,249	$1,580,369	$110,120	7.5%	2
3	Medium Light and Power	$1,284,389	$1,364,875	$80,486	6.3%	3
4	E-19	$1,551,902	$1,646,741	$94,838	6.1%	4
5	Streetlights	$69,889	$73,133	$3,244	4.6%	5
6	Standby	$57,808	$60,831	$3,023	5.2%	6
7	Agriculture	$870,309	$930,310	$60,000	6.9%	7
8	E-20	$1,122,193	$1,182,491	$60,298	5.4%	8
9	Total	$11,579,599	$12,313,882	$734,283	6.3%	9
	Direct Access and Community Choice Aggregation Service**					
10	Residential	$95,449	$105,971	$10,522	11.0%	10
11	Small Light and Power	$16,383	$17,758	$1,375	8.4%	11
12	Medium Light and Power	$108,288	$116,371	$8,083	7.5%	12
13	E-19	$240,671	$257,816	$17,145	7.1%	13
14	Standby	$967	$1,021	$54	5.5%	14
15	Agriculture	$3,113	$3,345	$232	7.5%	15
16	E-20	$267,566	$283,901	$16,335	6.1%	16
17	Total	$732,437	$786,182	$53,745	7.3%	17

* Customers who receive electric generation as well as transmission and distribution service from PG&E.
** Customers who purchase energy from non-PG&E suppliers.

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT C
GAS DEPARTMENT
SUMMARY OF REVENUES BY CUSTOMER CLASS
(Dollars in Thousands)

Gas Customer Class	Present Revenue	Proposed Revenue	Revenue Change	Percentage Revenue Change
Core Retail - Bundled Service*				
Residential	2,342,313	2,684,875	$342,562	14.6%
Small Commercial	646,342	730,574	$84,232	13.0%
Large Commercial	42,204	45,236	$3,032	7.2%
Natural Gas Vehicle (Uncompressed Service)	11,080	11,261	$182	1.6%
Natural Gas Vehicle (Compressed Service)	4,533	4,484	-$48	-1.1%
Total Core Retail Bundled	3,046,472	3,476,431	$429,958	14.1%
Noncore Retail - Transport-Only Service**				
Industrial Distribution	50,911	65,287	$14,375	28.2%
Industrial Transmission	109,583	121,388	$11,805	10.8%
Industrial Backbone	555	616	$61	10.9%
Electric Generation - D/T	38,763	40,474	$1,710	4.4%
Electric Generation - Backbone	26,858	28,043	$1,185	4.4%
Natural Gas Vehicle (Uncompressed Service)	334	362	$29	8.6%
Total Noncore Retail	227,005	256,170	29,165	12.8%
Wholesale Retail - Transport Only Service**				
Alpine Natural Gas	41	41	$0	0.0%
Coalinga	149	149	$0	0.0%
Island Energy	33	33	$0	0.0%
Palo Alto	1,451	1,451	$0	0.0%
West Coast Gas - Castle	103	132	$28	27.5%
West Coast Gas - Mather Distribution	117	153	$36	30.3%
West Coast Gas - Mather Transmission	25	25	$0	0.0%
Total Wholesale Retail	1,919	1,983	$64	3.3%
Unbundled Gas Transmission and Storage	174,832	174,832	$0	0.0%
Total	3,450,228	3,909,415	$459,187	13.3%

* C**ore Bundled rates include**: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees, Winter Gas Savings Program, and cost of gas; (ii) a transportation component that recovers CCC, CACs, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G-PPPS that recovers the costs of low income CARE, ESAP, customer EE, RD&D Program and BOE/CPUC Admin costs. Actual procurement rates change monthly.

**** Transportation Only rates include**: (i) a transportation component that recovers CCC, CACs, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a G-PPPS that recovers the costs of low-income CARE, ESAP, customer EE, RD&D Program and BOE/CPUC Admin costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

Exhibit D

Results of Operation at Proposed Rates

Table D-1
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Proposed Rates
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Test Year 2014 (A)	Attrition Year 2015 Increase (B)	Attrition Year 2015 Total (C)	Attrition Year 2016 Increase (D)	Attrition Year 2016 Total (E)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	4,333,021	220,325	4,553,345	234,339	4,787,684	1
2	Plus Other Operating Revenue	100,264	-	100,264	-	100,264	2
3	Total Operating Revenue	4,433,284	220,325	4,653,609	234,339	4,887,948	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	-	-	-	-	-	5
6	Storage	-	-	-	-	-	6
7	Transmission	1,036	29	1,065	25	1,090	7
8	Distribution	628,949	16,099	645,048	15,134	660,182	8
9	Customer Accounts	199,432	6,098	205,531	6,204	211,734	9
10	Uncollectibles	16,405	815	17,220	867	18,087	10
11	Customer Services	3,790	116	3,906	118	4,024	11
12	Administrative and General	490,248	16,817	507,065	18,353	525,418	12
13	Franchise Requirements	37,149	1,846	38,996	1,964	40,959	13
14	Amortization	58,768	5,606	64,374	6,140	70,514	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	14,608	(5,606)	9,002	(6,140)	2,862	17
18	Subtotal Expenses:	1,450,385	41,821	1,492,206	42,665	1,534,871	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	174,356	10,302	184,658	10,592	195,250	20
21	Payroll	46,150	1,371	47,521	1,411	48,932	21
22	Business	441	-	441	-	441	22
23	Other	1,398	-	1,398	-	1,398	23
24	State Corporation Franchise	89,758	7,890	97,648	8,962	106,611	24
25	Federal Income	210,040	12,106	222,146	24,595	246,742	25
26	Total Taxes	522,143	31,669	553,812	45,561	599,374	26
27	Depreciation	1,368,983	82,416	1,451,399	84,549	1,535,948	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	3,341,512	155,905	3,497,417	172,776	3,670,193	30
31	Net for Return	1,091,772	64,419	1,156,192	61,563	1,217,755	31
32	Rate Base	12,420,619	732,870	13,153,489	700,379	13,853,869	32
	RATE OF RETURN:						
33	On Rate Base	8.79%	8.79%	8.79%	8.79%	8.79%	33
34	On Equity	11.35%	11.35%	11.35%	11.35%	11.35%	34

Table D-2
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Proposed Rates
Electric Generation
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	1,962,485	68,785	2,031,270	97,825	2,129,095	1
2	Plus Other Operating Revenue	14,387	-	14,387	-	14,387	2
3	Total Operating Revenue	1,976,873	68,785	2,045,658	97,825	2,143,483	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	630,456	16,894	647,350	14,995	662,345	5
6	Storage	-	-	-	-	-	6
7	Transmission	4,122	115	4,237	99	4,337	7
8	Distribution	-	-	-	-	-	8
9	Customer Accounts	-	-	-	-	-	9
10	Uncollectibles	7,315	255	7,570	362	7,932	10
11	Customer Services	-	-	-	-	-	11
12	Administrative and General	276,692	9,491	286,183	10,358	296,542	12
13	Franchise Requirements	16,566	576	17,142	820	17,962	13
14	Amortization	207	-	207	-	207	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(125,042)	(20,000)	(145,042)	-	(145,042)	17
18	Subtotal Expenses:	810,315	7,332	817,647	26,634	844,282	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	54,033	2,370	56,403	2,418	58,821	20
21	Payroll	34,912	1,037	35,949	1,068	37,017	21
22	Business	249	-	249	-	249	22
23	Other	789	-	789	-	789	23
24	State Corporation Franchise	35,063	2,703	37,766	3,543	41,309	24
25	Federal Income	121,790	4,025	125,815	12,889	138,704	25
26	Total Taxes	246,836	10,134	256,970	19,918	276,888	26
27	Depreciation	416,213	19,963	436,176	20,564	456,740	27
28	Fossil Decommissioning	36,085	-	36,085	-	36,085	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,509,449	37,430	1,546,879	67,116	1,613,995	30
31	Net for Return	467,423	31,355	498,779	30,709	529,488	31
32	Rate Base	5,317,672	356,717	5,674,390	349,363	6,023,752	32
	RATE OF RETURN:						
33	On Rate Base	8.79%	8.79%	8.79%	8.79%	8.79%	33
34	On Equity	11.35%	11.35%	11.35%	11.35%	11.35%	34

Table D-3
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Proposed Rates
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	1,783,165	201,430	1,984,595	166,394	2,150,990	1
2	Plus Other Operating Revenue	26,989	-	26,989	-	26,989	2
3	Total Operating Revenue	1,810,155	201,430	2,011,585	166,394	2,177,979	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Procurement	4,575	121	4,695	124	4,820	5
6	Storage	-	-	-	-	-	6
7	Transmission	-	-	-	-	-	7
8	Distribution	407,496	62,927	470,423	23,608	494,031	8
9	Customer Accounts	153,173	4,684	157,856	4,765	162,621	9
10	Uncollectibles	6,551	729	7,280	602	7,882	10
11	Customer Services	2,856	89	2,945	90	3,035	11
12	Administrative and General	263,247	16,541	279,788	11,872	291,660	12
13	Franchise Requirements	24,432	2,719	27,150	2,246	29,396	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(59)	-	(59)	-	(59)	17
18	Subtotal Expenses:	862,271	87,809	950,080	43,306	993,387	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	42,233	3,624	45,858	3,721	49,579	20
21	Payroll	34,543	1,026	35,569	1,056	36,626	21
22	Business	237	-	237	-	237	22
23	Other	751	-	751	-	751	23
24	State Corporation Franchise	15,827	5,074	20,901	5,829	26,730	24
25	Federal Income	47,839	11,379	59,218	19,420	78,638	25
26	Total Taxes	141,430	21,104	162,534	30,027	192,561	26
27	Depreciation	465,176	41,249	506,426	42,243	548,669	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,468,877	150,162	1,619,040	115,577	1,734,617	30
31	Net for Return	341,277	51,268	392,545	50,818	443,363	31
32	Rate Base	3,882,562	583,251	4,465,813	578,132	5,043,945	32
	RATE OF RETURN:						
33	On Rate Base	8.79%	8.79%	8.79%	8.79%	8.79%	33
34	On Equity	11.35%	11.35%	11.35%	11.35%	11.35%	34

Exhibit E

General Description of PG&E's Electric and Gas Department Plant

Table E-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
			Electric Intangible		
1	EIP30201	302	Franchises & Consents	106,920	42,820
2	EIP30301	303	USBR - Limited Term Electric	1,000	1,000
3	EIP30303	303	Computer Software	14,547	8,656
4			**Total Electric Intangible Plant**	122,467	52,475
			Electric Steam Production - Fossil		
5	ESF31001	310	Land	574	-
6	ESF31002	310	Land Rights	3,164	-
7	ESF31101	311	Prod Fossil: Structures &	2,124	1,039
8	ESF31201	312	Prod Fossil: Boiler Plant	-	13,684
9	ESF31301	313	Prod Fossil: Engine & Engi	-	-
10	ESF31401	314	Prod Fossil: Turbogenerato	-	2,833
11	ESF31501	315	Prod Fossil: Accessory Ele	-	1,069
12	ESF31601	316	Prod Fossil: Miscellaneous	-	
13			**Total Electric Steam Production - Fossil**	5,862	18,625
			Electric Steam Production - Combined Cycle		
14	ESF31103	311	Structures & Improvements	103,949	6,967
15	ESF31203	312	Boiler Plant Equipment	262,692	14,547
16	ESF31205	312	Boiler Plant Equipment	1,469	147
17	ESF31403	314	Turbogenerator Units	229,469	14,726
18	ESF31503	315	Accessory Electrical Equipment	44,707	2,993
19	ESF31603	316	Miscellaneous Power Plant Equipment	24,391	1,454
20			**Total Electric Steam Production - Combined Cycle**	666,677	40,835
			Electric Nuclear Production		
21	ENP10900	109	Diablo Canyon FAS 109 Gross-up	468,499	468,499
22	ENP32001	320	Land	35,462	17,174
23	ENP32002	320	Land Rights	4,414	4,414
24	ENP32102	321	Post 2001 Structr & Imp	41,305	553
25	ENP32201	322	Reactor Plant Equip Unit 2	642,934	135,003
26	ENP32202	322	Post 2001 Reactor Plant Eqp	371,406	(4,575)
27	ENP32302	323	Post 2001 Turbogenerator Units	171,411	10,921
28	ENP32402	324	Post 2001 Access Elec Eqp	54,483	809
29	ENP32502	325	Post 2001 Misc Pwr Plnt Eqp	137,604	1,608
30	ENP32100	321	Prod Nucl: Structures & Im	938,816	944,594
31	ENP32200	322	Reactor Plant Equipment	2,322,680	2,290,533
32	ENP32300	323	Prod Nucl: Turbogenerator	956,793	960,122
33	ENP32400	324	Accessory Electric Equip	714,190	717,564
34	ENP32401	324	Acc Electrical Eqp (HBPP)	-	-
35	ENP32500	325	Misc Power Plant Equipment	492,144	492,521
36	ENP32501	325	Misc PP Equip (HBPP)	-	-
37			**Total Electric Nuclear Production**	7,352,142	6,039,742
			Electric Hydroelectric Production		
38	EHP30200	302	Franchises/Consents	-	-
39	EHP33001	330	Land	34,011	-
40	EHP33003	330	Land: Recreation	62	-
41	EHP33004	330	Land Rights	15,029	-
42	EHP33005	330	Land Rights: F/W	6	-
43	EHP33006	330	Land Rights: Recrtn	2,056	-
44	EHP33101	331	Prod Hydro: Structures & I	137,034	98,502
45	EHP33102	331	Prod Hydro: Structures & I	313	145
46	EHP33103	331	Prod Hydro: Structures & I	16,212	11,970
47	EHP33201	332	Prod Hydro: Resevoirs/Dams	1,153,266	774,598
48	EHP33202	332	Prod Hydro: Resvrs/Dams/Wt	13,230	4,635
49	EHP33203	332	Prod Hydro: Resevoirs/Dams	18,609	13,122
50	EHP33300	333	Prod Hydro: Water Wheels,	364,745	175,253

Table E-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
51	EHP33400	334	Prod Hydro: Accessory Elec	131,632	56,334
52	EHP33500	335	Prod Hydro: Miscellaneous	46,502	12,946
53	EHP33600	336	Prod Hydro: Roads, Railroa	42,355	24,828
54			**Total Electric Hydroelectric Production**	1,975,061	1,172,333
			Electric Hydroelectric Production - Helms Pumped Storage		
55	EHH30200	302	Franchises/Consents	-	-
56	EHH33001	330	Land	3	-
57	EHH33004	330	Land Rights	0	-
58	EHH33101	331	Structures & Improvements	165,108	162,789
59	EHH33201	332	Reservoirs, Dams & Waterways	412,946	415,187
60	EHH33300	333	Waterwheels, Turbines & Generators	184,766	151,934
61	EHH33400	334	Accessory Electrical Equipment	48,542	41,718
62	EHH33500	335	Miscellaneous Power Plant Equipment	15,144	14,594
63	EHH33600	336	Roads, Railroads & Bridges	8,724	8,451
64			**Total Hydroelectric Production - Helms**	835,232	794,672
			Electric Other Production		
65	EOP34001	340	Land	4,261	-
66	EOP34002	340	Land Rights	3,121	-
67	EOP34100	341	Structures & Improvements	29	(157)
68	EOP34200	342	Fuel Holders/Producers/Accsry	6	(28)
69	EOP34300	343	Prime Movers	38	211
70	EOP34400	344	Generators	683	(3,642)
71	EOP34500	345	Accessory Equipment	17	(358)
72	EOP34600	346	Miscellaneous Equipment	298	(15)
73			**Total Electric Other Production**	8,452	(3,990)
			Electric Other Production - Combined Cycle		
74	EOP34101	341	Structures & Improvements	139,693	6,701
75	EOP34201	342	Fuel Holders/Producers/Accsry	10,548	553
76	EOP34301	343	Prime Movers	219,582	11,970
77	EOP34401	344	Generators	24,753	1,042
78	EOP34501	345	Accessory Equipment	103,700	6,392
79	EOP34601	346	Miscellaneous Equipment	57,106	3,267
80			**Total Electric Other Production - Combined Cycle**	555,382	29,926
			Electric Other Production - Solar		
81	EOP34102	341	Solar Struc & Impr	21,143	241
82	EOP34402	344	Solar Gen Equip	149,135	1,683
83	EOP34403	344	Sol Gen Treas Grants	-	-
84	EOP34404	344	Fuell Cell	20,297	1,146
85	EOP34502	345	Solar Inverter	17,217	197
86	EOP34503	345	Solar Acc Elect Eq	19,480	220
87	EOP34602	346	Miscellaneous Equipment	20,789	1,254
88			**Total Electric Other Production - Solar**	248,061	4,741
89			**Total Electric Production**	11,646,869	8,096,885
			Electric Transmission		
90	ETP35001	350	Trans Plant: Land	47,933	2
91	ETP35002	350	Trans Plant: Land Rights	173,258	34,595
92	ETP35201	352	Trans Plant: Structures &	223,363	57,487
93	ETP35202	352	Trans Plant: Structues & I	58,022	2,609
94	ETP35301	353	Trans Plant: Station Equip	3,130,232	702,489
95	ETP35302	353	Trans Plant: Step Up Trans	144,081	93,262
96	ETP35303	353	Post 2008 Fossil Gen: Plan	61,509	3,967
97	ETP35400	354	Trans Plant: Towers & Fixt	502,635	291,810
98	ETP35401	354	Post 2008 Fossil Gen: Tow	15,732	1,221
99	ETP35500	355	Trans Plant: Poles & Fixtu	565,618	242,822

Table E-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
100	ETP35600	356	Trans Plant: OH Conductor/	980,222	468,907
101	ETP35601	356.01	Post 2008 Fossil Gen: OH C	2,744	277
102	ETP35700	357	Trans Plant: UG Conduit	351,522	47,454
103	ETP35800	358	Trans Plant: UG Conductor/	253,168	36,070
104	ETP35900	359	Trans Plant: Roads & Trail	49,223	3,636
105	ETX35201	352	Path 15 Trans Plant: Struc	-	-
106	ETX35301	353	Path 15 Station Eqp	38,247	36,787
107	ETX35400	354	Path 15 Towers & Fix	5,881	5,651
108	ETX35500	355	Path 15 Poles & Fixt	34	32
109	ETX35600	356	Path 15 OH CDR/Dev	251	243
110	NTP35201	352	Structures & Improvements	4,567	4,625
111	NTP35202	352	Structures & Improvements-Eqpt	285	289
112	NTP35301	353	Station Equipment	5,932	6,144
113	NTP35302	353	Step-up Transformers	77,478	47,384
114			**Total Electric Transmission**	6,691,936	2,087,765
			Electric Distribution		
115	EDP36001	360	Land	56,760	(0)
116	EDP36002	360	Land Rights	115,350	(0)
117	EDP36101	361	Structures & Improvements	228,646	65,155
118	EDP36102	361	Structures & Improvements-Eqpt	35,514	6,176
119	EDP36200	362	Station Equipment	2,186,700	635,598
120	EDP36300	363	Storage Battery	335	238
121	EDP36400	364	Poles, Towers, & Fixtures	2,797,339	1,359,825
122	EDP36500	365	OH Conductors & Devices	3,380,645	1,648,949
123	EDP36600	366	Underground Conduit	2,261,437	613,122
124	EDP36700	367	UG Conductors & Devices	3,265,649	1,822,038
125	EDP36801	368	Transformers (Inst prior 1960)	1,600,855	505,425
126	EDP36802	368	Line Transformers-Underground	443,552	163,131
127	EDP36901	369	Services-Overhead	691,228	500,084
128	EDP36902	369	Services-Underground	1,975,795	1,015,801
129	EDP37000	370	Meters	67	(12,937)
130	EDP37001	370	SmartMeter	916,809	35,951
131	EDP37100	371	Installation on Customer Premises	27,314	31,966
132	EDP37200	372	Leased Property on Cust. Prem.	895	970
133	EDP37301	373	Street Light-Overhead Conductors	11,650	9,121
134	EDP37302	373	Street Light-Conduit & Cables	27,640	13,088
135	EDP37303	373	Street Light-Lamps & Equipment	94,707	70,822
136	EDP37304	373	Street Light-Electroliers	33,058	24,172
137			**Total Electric Distribution**	20,151,944	8,508,699
			Electric General		
138	EGP38901	389	Land	6	-
139	EGP38902	389	Land Rights	415	-
140	EGP39000	390	Structures & Improvements	7,687	5,130
141	EGP39100	391	Office Furniture & Equipment	13,847	2,558
142	EGP39400	394	Shop Equipment	59,861	20,617
143	EGP39500	395	Laboratory Equipment	5,508	1,105
144	EGP39600	396	Power Operated Equipment	313	195
145	EGP39700	397	Communication Equipment	8,923	5,169
146	EGP39708	397	SM Elect Netwk Equip	0	0
147	EGP39800	398	Miscellaneous Equipment	10,441	(1,500)
148	NGP39100	391	Office Furniture & Equipment	179	-
149	NGP39800	398	Miscellaneous Equipment	1,879	1
150	NGP38901	389	Land	4	4
151			**Total Electric General Plant**	109,063	33,281
152			**TOTAL ELECTRIC PLANT AND RESERVE**	38,722,279	18,779,105

Table E-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
			Intangible		
1	GIP30202	302	Franchises & Consents	674	257
2	GIP30302	303	Computer Software	2,351	1,566
3			**Total Gas Intangible Plant**	3,025	1,824
			Intangible- Line 401		
4	GIE30302	303.02	Miscellaneous Intangible Plant	583	178
5			**Total Gas Intangible Plant- Line 401**	583	178
6			**Total Gas Intangible**	3,608	2,002
			Production		
7	GPP30401	304	Land	2	-
8	GPP30402	304	Land Rights	48	-
9	GPP30500	305	Structures & Improvements	130	200
10	GPP31100	311	Liquified Petroleum Gas Equipment	422	9
11			**Total Gas Production**	601	209
			Underground Storage		
12	GUS35011	350.0	Land	6,488	-
13	GUS35012	350.0	Land Rights	128	-
14	GUS35023	350.2	Leaseholds	7,220	6,073
15	GUS35024	350.2	Rights-of-Way (ROW)	1,796	1,064
16	GUS35110	351.1	Well Structures	4,581	2,570
17	GUS35120	351.2	Compressor Station Structures	6,657	3,821
18	GUS35130	351.3	Measuring & Reg Sta Structures	10,953	7,321
19	GUS35140	351.4	Other Structures	6,107	1,712
20	GUS35200	352	Wells	191,659	62,030
21	GUS35300	353	Lines	99,015	24,911
22	GUS35400	354	Compressor Station Equipment	98,086	26,459
23	GUS35500	355	Measuring & Reg Sta Equipment	52,712	30,094
24	GUS35600	356	Purification Equipment	58,107	23,916
25	GUS35700	357	Other Equipment	9,706	2,441
26			**Total Underground Storage**	553,216	192,412
			Local Storage		
27	GLS36001	360	Land	988	-
28	GLS36002	360	Land Rights	117	-
29	GLS36101	361	Structures & Improvements	1,520	1,078
30	GLS36200	362	Gas Holders	5,704	2,793
31	GLS36300	363	Purification Equipment	2	1
32	GLS36330	363.3	Compressor Station Equipment	608	505
33	GLS36340	363.4	Measuring & Reg Sta Equipment	227	70
34	GLS36350	363.5	Other Equipment	3,075	2,011
35			**Total Local Storage**	12,241	6,458
			Total Natural Gas Storage	565,457	198,870

Table E-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
			Gas Transmission		
36	GTP36511	365.11	Land & Land Rights	8,558	5,736
37	GTP36512	365.12	Rights-of-Way (ROW)	37,637	21,520
38	GTP36610	366.1	Compressor Station Structures	25,733	14,986
39	GTP36620	366.2	Measuring & Reg Sta Structures	11,683	4,913
40	GTP36630	366.3	Other Structures	19,667	7,631
41	GTP36700	367	Mains	1,669,423	701,906
42	GTP36702	367	Trans Plant: Feeder Mains	-	-
43	GTP36800	368	Compressor Station Equipment	375,546	185,837
44	GTP36900	369	Odorizing Equipment	200,020	74,563
45	GTP37100	371	Other Equipment	45,040	22,849
46			**Total Gas Transmission**	2,393,307	1,039,943
			Gas Transmission- Line 401		
47	GTE36511	365.11	Land & Land Rights	784	302
48	GTE36512	365.12	Rights-of-Way (ROW)	18,860	7,266
49	GTE36610	366.1	Compressor Station Structures	10,075	3,839
50	GTE36620	366.2	Measuring & Reg Sta Structures	1,066	600
51	GTE36630	366.3	Other Structures	750	275
52	GTE36700	367	Mains	639,530	277,389
53	GTE36800	368	Compressor Station Equipment	125,384	77,753
54	GTE36900	369	Odorizing Equipment	5,855	3,251
55			**Total Gas Transmission- Line 401**	802,304	370,674
			Gas Transmission- STANPAC		
56	GTS36511	365	STANPAC: Land & Land Rights	7	-
57	GTS36520	365	STANPAC: Rights-of-Way	1,807	892
58	GTS36620	366	STANPAC: Measuring & Reg Sta Structures	89	54
59	GTS36630	366	STANPAC: Other Structures	27	22
60	GTS36700	367	STANPAC: Mains	30,707	11,185
61	GTS36900	369	STANPAC: Odorizing Equipment	5,151	3,151
62	GTS37000	370	STANPAC: Communication Equipment	87	59
63	GTS37100	371	Other Equipment	297	299
64			**Total Gas Transmission- STANPAC**	38,173	15,663
65			**Total Gas Transmission**	3,233,784	1,426,280
			Gas Distribution		
66	GDP37401	374	Land	523	-
67	GDP37402	374	Land Rights	23,229	12
68	GDP37500	375	Structures & Improvements	2,549	707
69	GDP37601	376	Mains	2,513,182	1,316,238
70	GDP37700	377	Compressor Station Equipment	2,285	544
71	GDP37800	378	Odorizing Equipment	157,169	79,332
72	GDP38000	380	Services	2,625,154	2,120,496
73	GDP38100	381	Meters	733,766	210,527
74	GDP38300	383	House Regulators	164,816	98,295
75	GDP38500	385	Meas & Reg Sta Equip-Industrial	34,457	22,154
76	GDP38600	386	Other Property on Customer Premises	166	80
77	GDP38700	387	Other Equipment	19,496	11,933
78			**Total Gas Distribution**	6,276,791	3,860,319

Table E-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

Line	Asset Class	FERC Account	Description	Utility Plant	Utility Reserve
			Gas General		
79	GGP38901	389	Land	189	-
80	GGP38902	389	Land Rights	51	-
81	GGP39000	390	Structures & Improvements	11,774	7,425
82	GGP39100	391	Office Furniture & Equipment	5,006	1,884
83	GGP39400	394	Shop Equipment	14,227	2,757
84	GGP39500	395	Laboratory Equipment	426	63
85	GGP39600	396	Power Operated Equipment	42	7
86	GGP39708	397	SM Gas Netwk Equip	25,576	(3,317)
87	GGP39800	398	Miscellaneous Equipment	5,256	936
88	GGP39900	399	Other Tangible Property	124	54
89			**Total Gas General**	62,671	9,809
			Gas General- Line 401		
90	GGE38902	389	Land Rights	110	-
91	GGE39000	390	Structures & Improvements	16,576	8,764
92	GGE39100	391	Office Furniture & Equipment	723	395
93	GGE39400	394	Shop Equipment	902	103
94	GGE39500	395	Laboratory Equipment	469	52
95	GGE39600	396	Power Operated Equipment	-	-
96	GGE39800	398	Miscellaneous Equipment	8,162	5,031
97	GGE39900	399	Other Tangible Property	1,846	1,015
98			**Total Gas General- Line 401**	28,788	15,360
			Gas General- STANPAC		
99	GGS39210		STANPAC: Transport Equ	27	27
100	GGS39220		STANPAC: Transport Eqp	12	12
101	GGS39100	391	STANPAC: Office Furniture & Equipment	7	7
102	GGS39300	393	STANPAC: Stores Equipment	1	1
103	GGS39400	394	STANPAC: Tools/Shop/Work Equipment	12	12
104	GGS39500	395	STANPAC: Laboratory Equipment	2	2
105	GGS39800	398	STANPAC: Miscellaneous Equipment	16	15
106			**Total Gas General- STANPAC**	76	75
107			**Total Gas General**	91,534	25,244
108			**TOTAL GAS PLANT AND RESERVE**	10,171,776	5,512,924

Table E-3
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

				Utility	
Line	Asset Class	FERC Account	Description	Plant	Reserve
1	CMP30101	301	Organization	132	132
2	CMP30200	302	Intangible Plant: Franchis	103	-
3	CMP30302	303	Computer Software	581,868	222,314
4	CMP30304	303	Computer Software - CIS	603,631	247,360
5	CMP38901	389	Land	68,781	-
6	CMP38902	389	Land Rights	10,726	-
7	CMP39000	390	Structures & Improvements	1,125,307	477,018
8	CMP39001	390	Comm Plant: Leasehold Impr	-	-
9	CMP39101	391	Office Machines & Computer Eqpt	207,386	139,253
10	CMP39102	391	PC Hardware	80,429	11,081
11	CMP39103	391	Office Furniture & Equipment	120,264	17,354
12	CMP39104	391	Off Mach & Computer Eqpt - CIS	155,603	43,338
13	CMP39201	392	Aircraft	25,706	9,673
14	CMP39202	392	Class P	6,144	4,238
15	CMP39203	392	Class C - 2	19,324	13,282
16	CMP39204	392	Class C - 4	12,135	6,864
17	CMP39205	392	Class T - 1	73,746	26,625
18	CMP39206	392	Class T - 3	235,651	90,266
19	CMP39207	392	Class T - 4	244,525	99,427
20	CMP39208	392	Vessels	651	690
21	CMP39209	392	Trailers	26,687	18,836
22	CMP39300	393	Stores Equipment	6,389	292
23	CMP39400	394	Shop Equipment	56,955	31,491
24	CMP39500	395	Laboratory Equipment	11,144	956
25	CMP39600	396	Power Operated Equipment	97,031	16,082
26	CMP39701	397	Communication - Common Eqpt	31,068	10,829
27	CMP39702	397	Communication - Data Systems	73,725	31,028
28	CMP39703	397	Communication - Radio Systems	27,938	11,987
29	CMP39704	397	Communication - Voice Systems	31,840	14,114
30	CMP39705	397	Communication - Transm Systems	289,701	81,722
31	CMP39706	397	Comm - Transm Sys AMI-G	341,219	39,247
32	CMP39707	397	Comm - Transm Sys AMI-E	(87)	206
33	CMP39708	397	Communication Network	115,976	12,809
34	CMP39800	398	Miscellaneous Equipment	15,215	4,256
35	CMP39900	399	Other Tangible Property	14	6
36	CNP30302	303	DCPP Software	73,526	7,119
37	CNP38901	389	DCPP Land	0	0
38	CNP38902	389	DCPP Land Rights	5	5
39	CNP39000	390	DCPP Structures & Improve-Office-Eqpt	43,596	39,397
40	CNP39101	391	DCPP Office Machines & Computer Eqpt	150	(14)
41	CNP39102	391	DCPP PC Hardware	612	(267)
42	CNP39103	391	DCPP Office Furniture & Equipment	6,274	5,028
43	CNP39201	392	DCPP Aircraft	-	-
44	CNP39202	392	DCPP Class P	41	41
45	CNP39203	392	DCPP Class C - 2	789	585
46	CNP39204	392	DCPP Class C - 4	238	163
47	CNP39205	392	DCPP Class T - 1	680	435
48	CNP39206	392	DCPP Class T - 3	546	316
49	CNP39207	392	DCPP Class T - 4	771	294
50	CNP39208	392	DCPP Vessels	115	115
51	CNP39209	392	DCPP Trailers	760	682
52	CNP39300	393	DCPP Stores Equipment	90	13
53	CNP39400	394	DCPP Shop Equipment	389	390
54	CNP39500	395	DCPP Laboratory Equipment	2,362	1,005
55	CNP39600	396	DCPP Power Operated Equipment	5,954	1,568
56	CNP39701	397	DCPP Communication - Common Eqpt	1,668	629

Table E-3
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

				Utility	
Line	Asset Class	FERC Account	Description	Plant	Reserve
57	CNP39702	397	DCPP Communication - Data Systems	39	(222)
58	CNP39703	397	DCPP Communication - Radio Systems	351	186
59	CNP39704	397	DCPP Communication - Voice Systems	5,809	4,548
60	CNP39705	397	DCPP Communication - Transm Systems	10,108	9,367
61	CNP39800	398	DCPP Miscellaneous Equipment	5,395	1,548
62			**TOTAL COMMON PLANT AND RESERVE**	4,857,196	1,755,708

Table E-4
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OPERATIVE PLANT AND DEPRECIATION RESERVE
AS OF DECEMBER 31, 2011
(000's)

GL Account	Summary	Plant	Reserve
101	**Plant in Service**		
	Plant in Service - Electric	38,722,279	
	Plant in Service - Gas	10,133,527	
	Plant in Service - Common	4,857,196	
	Corp Adj: Impairment Reclass	(7,029,588)	
	Intangible Asset Re-class to Non-Current Asset (Hydro license)	(112,021)	
	Mirant Settlement	66,886	
	FAS 90 adjustments for SmartMeter	(33,396)	
	Electro Mechanical Meter Reclass	58,997	
	FAS 143 Asset Retirement Costs Fossil/Nuclear	167,648	
	FIN 47 Asset Retirement Cost	83,063	
	Treasury Grant (Fuel Cell and Solar)	(67,804)	
	Capital Lease	408,358	
	Other	(2,421)	
117	Gas Stored Underground	55,720	
120	Nuclear Fuel inventory	434,553	
	Total Utility Plant in Service	47,742,996	
	Standard Pacific Gas Line	38,587	
	Total PG&E Plant in Service (Balance Sheet)	47,781,583	
108/111	**Accumulated Depreciation and Amortization**		
	Electric		18,779,105
	Gas		5,497,186
	Common		1,755,708
	Impairment Reclassification		(7,029,588)
	Cost of Removal Reclass		(3,430,428)
	Intangibles Reclass		(46,533)
	Mirant Settlement		6,242
	PV Grant		(937)
	Electro-Mechanical Meter Reclass		66,030
	Plant Acquisition Adjustment (EPA)		2,145
	FIN 47		49,266
	FAS 143 ARO asset depr- Nuclear		37,020
	FAS 143 ARO asset depr- Fossil		35,489
	QF Capital Leases		160,186
	Other		494
	Total Utility Accumulated Depreciation		15,881,385
	StanPac		16,003
	Total PG&E Accumulated Depreciation (Balance Sheet)		15,897,388

Exhibit F

Summary of Earnings (2010)

PACIFIC GAS AND ELECTRIC COMPANY
ALL OPERATING DEPARTMENTS
REVENUES, EXPENSES, RATE BASES AND RATES OF RETURN
YEAR 2010 RECORDED
ADJUSTED FOR RATEMAKING
(000$)

Line No.		Electric Operations	Gas Operations	Total Utility Operations
1	**Operating Revenue**	10,272,443	3,341,762	13,614,205
2	Operation Expenses	6,199,632	2,187,052	8,386,685
3	Maintenance Expenses	600,193	141,615	741,808
4	Depreciation Expense	1,003,133	337,696	1,340,829
5	Amort & Depletion of Utility Plant	139,785	34,667	174,452
6	Regulatory Debits	0	0	0
7	(Less) Regulatory Credits	0	0	0
8	Taxes Other Than Income Taxes	286,256	78,601	364,858
9	Federal Income Taxes	506,609	153,970	660,579
10	State Income Taxes	71,736	37,977	109,713
11	(Less) Gains from Disp of Utility Plant	(1,190)	(351)	(1,541)
12	Losses from Utility Plant	0	0	0
13	(Less) Gains from Disposition Utility Plant	(18)	0	(18)
14	**Operating Income**	1,466,307	370,534	1,836,840
15	Weighted Average Rate Base	16,721,231	4,531,858	21,253,089
16	**Rate of Return**	**8.77%**	**8.18%**	**8.64%**

Exhibit G

Statement of Election of Method of Computing Depreciation for Federal Income Tax

Statement of Method for Depreciation – Rule 3.2(a)(7)

PG&E depreciates utility plant in its financial statements on a straight-line remaining life basis, according to the estimated useful life of plant property. For federal income tax accrual purposes, PG&E generally computes depreciation using the straight-line method for tax property additions prior to 1954 and liberalized depreciation, which includes Class Life and Asset Depreciation Range Systems (ADRS), on tax property additions after 1954 and prior to 1981. For financial reporting and ratesetting purposes, PG&E uses "flow through accounting" for such properties. For tax property additions in years 1981 through 1986, the Company computes its tax depreciation using the Accelerated Cost Recovery System (ACRS). For additions after 1986, PG&E computes its tax depreciation using the Modified Accelerated Cost Recovery System (MACRS) and, since 1982, has normalized the effects of the depreciation difference in accordance with the Economic Recovery Tax Act of 1981 and the Tax Reform Act of 1986.

Exhibit H

Revenues at Present Rates in Results of Operations Report

Table H-1
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Present Rates
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	3,767,728	-	3,767,728	-	3,767,728	1
2	Plus Other Operating Revenue	110,558	-	110,558	-	110,558	2
3	Total Operating Revenue	3,878,287	-	3,878,287	-	3,878,287	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	-	-	-	-	-	5
6	Storage	-	-	-	-	-	6
7	Transmission	1,036	29	1,065	25	1,090	7
8	Distribution	628,949	16,099	645,048	15,134	660,182	8
9	Customer Accounts	199,432	6,098	205,531	6,204	211,734	9
10	Uncollectibles	14,351	-	14,351	-	14,351	10
11	Customer Services	3,790	116	3,906	118	4,024	11
12	Administrative and General	490,248	16,817	507,065	18,353	525,418	12
13	Franchise Requirements	32,499	-	32,499	-	32,499	13
14	Amortization	58,768	5,606	64,374	6,140	70,514	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	14,608	(5,606)	9,002	(6,140)	2,862	17
18	Subtotal Expenses:	1,443,681	39,159	1,482,840	39,834	1,522,674	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	174,356	10,302	184,658	10,592	195,250	20
21	Payroll	46,150	1,371	47,521	1,411	48,932	21
22	Business	441	-	441	-	441	22
23	Other	1,398	-	1,398	-	1,398	23
24	State Corporation Franchise	41,289	(11,352)	29,938	(11,503)	18,435	24
25	Federal Income	18,137	(47,112)	(28,974)	(49,698)	(78,672)	25
26	Total Taxes	281,772	(46,790)	234,981	(49,197)	185,784	26
27	Depreciation	1,368,983	82,416	1,451,399	84,549	1,535,948	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	3,094,436	74,785	3,169,220	75,186	3,244,406	30
31	Net for Return	783,851	(74,785)	709,066	(75,186)	633,880	31
32	Rate Base	12,420,619	732,870	13,153,489	700,379	13,853,869	32
	RATE OF RETURN:						
33	On Rate Base	6.31%	-10.20%	5.39%	-10.74%	4.58%	33
34	On Equity	6.58%	-25.18%	4.81%	-26.20%	3.24%	34

Table H-2
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Present Rates
Electric Generation
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	1,737,200	-	1,737,200	-	1,737,200	1
2	Plus Other Operating Revenue	11,613	-	11,613	-	11,613	2
3	Total Operating Revenue	1,748,813	-	1,748,813	-	1,748,813	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	630,456	16,894	647,350	14,995	662,345	5
6	Storage	-	-	-	-	-	6
7	Transmission	4,122	115	4,237	99	4,337	7
8	Distribution	-	-	-	-	-	8
9	Customer Accounts	-	-	-	-	-	9
10	Uncollectibles	6,471	-	6,471	-	6,471	10
11	Customer Services	-	-	-	-	-	11
12	Administrative and General	276,692	9,491	286,183	10,358	296,542	12
13	Franchise Requirements	14,654	-	14,654	-	14,654	13
14	Amortization	207	-	207	-	207	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(125,042)	(20,000)	(145,042)	-	(145,042)	17
18	Subtotal Expenses:	807,560	6,501	814,061	25,453	839,514	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	54,033	2,370	56,403	2,418	58,821	20
21	Payroll	34,912	1,037	35,949	1,068	37,017	21
22	Business	249	-	249	-	249	22
23	Other	789	-	789	-	789	23
24	State Corporation Franchise	15,146	(3,304)	11,841	(5,000)	6,842	24
25	Federal Income	48,348	(12,788)	35,559	(18,834)	16,726	25
26	Total Taxes	153,476	(12,686)	140,791	(20,348)	120,443	26
27	Depreciation	416,213	19,963	436,176	20,564	456,740	27
28	Fossil Decommissioning	36,085	-	36,085	-	36,085	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,413,335	13,779	1,427,113	25,668	1,452,782	30
31	Net for Return	335,478	(13,779)	321,699	(25,668)	296,031	31
32	Rate Base	5,317,672	356,717	5,674,390	349,363	6,023,752	32
	RATE OF RETURN:						
33	On Rate Base	6.31%	-3.86%	5.67%	-7.35%	4.91%	33
34	On Equity	6.57%	-12.99%	5.34%	-19.69%	3.89%	34

Table H-3
Pacific Gas and Electric Company
2014 CPUC General Rate Case (Notice of Intent (NOI))
Results of Operations at Present Rates
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Test Year 2014 (A)	Attrition Year 2015 Increase (B)	Attrition Year 2015 Total (C)	Attrition Year 2016 Increase (D)	Attrition Year 2016 Total (E)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	1,323,978	-	1,323,978	-	1,323,978	1
2	Plus Other Operating Revenue	22,922	-	22,922	-	22,922	2
3	Total Operating Revenue	1,346,900	-	1,346,900	-	1,346,900	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Procurement	4,575	121	4,695	124	4,820	5
6	Storage	-	-	-	-	-	6
7	Transmission	-	-	-	-	-	7
8	Distribution	407,496	62,927	470,423	23,608	494,031	8
9	Customer Accounts	153,173	4,684	157,856	4,765	162,621	9
10	Uncollectibles	4,875	-	4,875	-	4,875	10
11	Customer Services	2,856	89	2,945	90	3,035	11
12	Administrative and General	263,247	16,541	279,788	11,872	291,660	12
13	Franchise Requirements	18,179	-	18,179	-	18,179	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(59)	-	(59)	-	(59)	17
18	Subtotal Expenses:	854,342	84,361	938,704	40,458	979,162	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	42,233	3,624	45,858	3,721	49,579	20
21	Payroll	34,543	1,026	35,569	1,056	36,626	21
22	Business	237	-	237	-	237	22
23	Other	751	-	751	-	751	23
24	State Corporation Franchise	(24,424)	(12,427)	(36,851)	(8,628)	(45,480)	24
25	Federal Income	(111,525)	(43,827)	(155,352)	(31,695)	(187,047)	25
26	Total Taxes	(58,185)	(51,604)	(109,789)	(35,546)	(145,335)	26
27	Depreciation	465,176	82,416	547,592	84,549	632,142	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,261,334	115,173	1,376,507	89,461	1,465,969	30
31	Net for Return	85,566	(115,173)	(29,607)	(89,461)	(119,069)	31
32	Rate Base	3,882,562	583,251	4,465,813	578,132	5,043,945	32
	RATE OF RETURN:						
33	On Rate Base	2.20%	-19.75%	-0.66%	-15.47%	-2.36%	33
34	On Equity	-1.32%	-43.53%	-6.83%	-35.32%	-10.10%	34

Exhibit I

Notice and Service of Application

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Department of General Services
Office of Buildings & Grounds
505 Van Ness Avenue, Room 2012
San Francisco, CA 94102

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda	Mariposa	Santa Barbara
Alpine	Mendocino	Santa Clara
Amador	Merced	Santa Cruz
Butte	Modoc	Shasta
Calaveras	Monterey	Sierra
Colusa	Napa	Siskiyou
Contra Costa	Nevada	Solano
El Dorado	Placer	Sonoma
Fresno	Plumas	Stanislaus
Glenn	Sacramento	Sutter
Humboldt	San Benito	Tehama
Kern	San Bernardino	Trinity
Kings	San Francisco	Tulare
Lake	San Joaquin	Tuolumne
Lassen	San Luis Obispo	Yolo
Madera	San Mateo	Yuba
Marin		

<u>Municipal Corporations</u>

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley
Millbrae
Milpitas
Modesto
Monte Sereno

Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City

Appendix 1
2014 General Rate Case Exhibit List

PACIFIC GAS AND ELECTRIC COMPANY
2014 GENERAL RATE CASE
EXHIBIT (PG&E-12), STATEMENTS OF QUALIFICATIONS
INDEX BY EXHIBIT AND CHAPTER

Exhibit	Chapter	Exhibit/Chapter Title	Witness
1		**Summary of PG&E's 2014 General Rate Case**	
1	Ch. 1		Anthony F. Earley, Jr.
1	Ch. 2	Overview	Christopher P. Johns
1	Ch. 3	Safety of the Public and Employees	Desmond A. Bell
1	Atch. 3A	Safety Metrics	Desmond A. Bell
1	Ch. 4	Risk Assessment and Planning	Anil Suri
1	Ch. 5	Summary of PG&E's Request	Shelly J. Sharp
1	Atch. 5A	Economic Impact of PG&E Proposed Generation, Distribution & Related Infrastructure Investments	Shelly J. Sharp
2		**Results of Operations**	
2	Ch. 1	Introduction	Redacted
2	Ch. 2	SAP FERC Translation	Redacted
2	Ch. 3	Electric Distribution O&M Expense	
2	Ch. 4	Gas Distribution O&M Expense	
2	Ch. 5	Customer Accounts Expense	
2	Ch. 6	Generation O&M Expense	
2	Ch. 7	Administrative and General Expenses	
2	Ch. 8	Payroll and Other Taxes	Laurie Shakur
2	Ch. 9	Electric, Gas and Common Plant	Charles M. Marre
2	Ch. 10	Depreciation Reserve and Expense	Charles M. Marre
2	Ch. 11	Depreciation Study	Redacted
2	Atch. 11A	Retirement Rate Method of Analysis	
2	Atch. 11B	Simulated Plant Balance Method	
2	Ch. 12	Income and Property Taxes	
2	Ch. 13	Working Cash	
2	Ch. 14	Gas and Electric Distribution and Generation Rate Base	Charles M. Marre
2	Ch. 15	Electric Revenues at Present Rates	Redacted
2	Ch. 16	Gas Revenues at Present Rates	
2	Ch. 17	Other Operating Revenues	
2	Ch. 18	Calculation of Revenue Requirement	
2	App. A	Detailed Results of Operations - Tables	
3		**Gas Distribution**	
3	Ch. 1	Gas Distribution Operations Policy and Introduction	Nickolas Stavropoulos
3	Ch. 2	System Operations Gas Control	Melvin J. Christopher
3	Ch. 3	Gas Distribution Mapping and Records	Sumeet Singh
3	Ch. 4	Gas Distribution Integrity Management Program	Redacted
3	Ch. 5	Pipe, Meter and Other Preventative Maintenance	Jodie L. Kubota
3	Ch. 6	Leak Survey and Repair	Redacted
3	Ch. 7	Gas Field Services and Response	Richard W. Yamaguchi
3	Ch. 8	Gas Distribution Capital and Investment Planning	Redacted
3	Ch. 9	New Business and Work at the Request of Others	
3	Ch. 10	Technical Training and Research and Development	Matthew G. Storment
3	Ch. 11	Gas Operations Technology Costs	Steven A. Whelan
3	Ch. 12	Gas Operations Building Projects, AGA Fees and PAS 55 Certification	Bill L. Gibson

Exhibit	Chapter	Exhibit/Chapter Title	Witness
4		**Electric Distribution**	
4	Ch. 1	Electric Distribution Operations Policy and Introduction	Geisha J. Williams
4	Ch. 2	Electric Operations Technology	Kevin J. Dasso
4	Ch. 3	Applied Technology Services	Kevin J. Dasso
4	Ch. 4	Electric Mapping and Records Management	Kevin J. Dasso
4	Ch. 5	Electric Distribution Maintenance	Redacted
4	Ch. 6	Pole Test and Treat, Restoration and Joint Utilities Coordination	
4	Ch. 7	Pole Replacement	Redacted
4	Ch. 8	Vegetation Management	Redacted
4	Ch. 9	New Business and Work at the Request of Others	
4	Ch. 10	Electric Emergency Recovery	Barry D. Anderson
4	Ch. 11	Distribution System Operations	Barry D. Anderson
4	Ch. 12	Electric Distribution Capacity	Manho Yeung
4	Ch. 13	Substation Asset Strategy	Manho Yeung
4	Ch. 14	Electric Engineering - Distribution Planning, Operations, & Power Quality	Manho Yeung
4	Ch. 15	Electric Distribution Reliability	Redacted
4	Ch. 16	Underground Asset Management	
4	Ch. 17	Distribution Automation and System Protection	
4	Ch. 18	Rule 20A	Redacted
4	Ch. 19	LED Streetlight Program	
4	Ch. 20	Electric Distribution Support Activities	
5		**Customer Care**	
5	Ch. 1	Customer Care Policy	Helen A. Burt
5	Ch. 2	Customer Inquiry Assistance	Steven H. Phillips
5	Ch. 3	Office Services	Steven H. Phillips
5	Ch. 4	Meter to Cash	Steven H. Phillips
5	Ch. 5	Metering	Steven H. Phillips
5	Ch. 6	Quality Assurance Program/Safety Net Program	Steven H. Phillips
5	Atch. 6A	Description of Quality Assurance Standards	Steven H. Phillips
5	Atch. 6B	Safety Net Program Eligibility Requirements for Storm Inconvenience Payments	Steven H. Phillips
5	Ch. 7	Customer Energy Solutions	Jess A. Brown
5	Ch. 8	Customer Retention	David E. Rubin
5	Ch. 9	Information Technology Programs	Brian F. Rich
5	Ch. 10	SmartMeter™ Program	James L. Meadows
6		**Energy Supply**	
6	Ch. 1	Energy Supply Operations Policy	John T. Conway
6	Ch. 2	Hydro Operations Costs	Michael L. Jones
6	Ch. 3	Nuclear Operations Costs	James R. Becker
6	Ch. 4	Fossil and Other Generation Operations Costs	Debbie Powell
6	Ch. 5	Energy Procurement Administration Costs	Kelly A. Everidge
6	Ch. 6	Energy Supply Ratemaking	Joseph F. O'Flanagan

Exhibit	Chapter	Exhibit/Chapter Title	Witness
7		**Shared Services and Information Technology**	
7	Ch. 1	Shared Services and Information Technology Policy and Introduction	Desmond A. Bell
7	Ch. 2	Safety Department	Mark C. Hughes
7	Ch. 3	Transportation Services	David M. Meisel
7	Ch. 4	Supply Chain - Materials Logistics and Planning	Lance C. Schultz
7	Ch. 5	Supply Chain - Sourcing Operations	Steve T. Coleman
7	Ch. 6	Real Estate	Corey J. Wong
7	Ch. 7	Environmental Program	Janet C. Loduca
7	Ch. 8	Information Technology Costs	Malia M. Wolf
7	Ch. 9	Information Technology Cybersecurity	James W. Sample
8		**Human Resources Policies**	
8	Ch. 1	Human Resources Policy	John R. Simon
8	Ch. 2	Workforce Diversity and Inclusion Policy	Joyce Ibardolasa
8	Atch. 2A	Annual Letter to Employees on Diversity EEO and AA	Joyce Ibardolasa
8	Ch. 3	Total Compensation Study	TBD (Consultant)
8	Ch. 4	Total Compensation Study Results	TBD
8	Ch. 5	Short-Term Incentive Plan and Labor Escalation Assumptions	Redacted
8	Ch. 6	Benefits, Health and Insurance	Redacted
8	Ch. 7	Retirement, Disability and Other Benefits, Including Trust Contributions	Redacted Ted Huntley
8	Ch. 8	Workers' Compensation Costs	Mark C. Hughes
8	Ch. 9	Workforce Management - Severance Program Costs	Andrew K. Williams
9		**Administrative and General Expenses**	
9	Ch. 1	Introduction	Redacted
9	Ch. 2	Finance Organization Costs	Bruce P. Fraser
9	Ch. 3	Risk and Audit Department Costs and Insurance Expenses	Megan S. Janis
9	Ch. 4	Human Resources Department and HR Technology Costs	Andrew K. Williams
9	Ch. 5	Regulatory Relations Department Costs	Amrit P. Singh
9	Ch. 6	Law Department and Related Costs	Sanford L. Hartman
9	Ch. 7	PG&E Corporation and Pacific Gas and Electric Company Executive Offices; and Corporate Secretary Department Costs	Linda Y.H. Cheng
9	Ch. 8	Corporate Affairs - Communications Department Costs	Craig A. Cussimanio
9	Ch. 9	Corporate Affairs - External Affairs Department Costs	Susan C. Martinez
9	Ch. 10	A&G Ratemaking Adjustments	Judith S. Gutierrez

Exhibit	Chapter	Exhibit/Chapter Title	Witness
10		**General Report**	
10	Ch. 1	Introduction	Shelly J. Sharp
10	Ch. 2	Balance Sheet and Statement of Operations	Jennifer K. Gardyne
10	Ch. 3	Escalation Rates	Redacted
10	Ch. 4	Electric Billings and Sales	
10	Ch. 5	Gas Billings and Sales	
10	Ch. 6	Illustrative Electric Rates	Redacted
10	Atch. 6A	Illustrative Electric Rates	
10	Ch. 7	Illustrative Gas Rates	Redacted
10	Ch. 8	Compliance with Prior Commission Decisions	Shelly J. Sharp
10	Ch. 9	Balancing Accounts	Teresa J. Hoglund
10	Ch. 10	PG&E's Planning and Budgeting Processes	Jason P. Wells
10	Ch. 11	Financing Proposals for Certain Long-Lived Assets	Redacted
10	Ch. 12	Alignment of Investor and Ratepayer Interests	Walter A. Campbell Jay D. Dore
11		**Post Test-Year Ratemaking**	
11	Ch. 1	Post Test-Year Ratemaking Proposal	David S. Thomason
11	Ch. 2	Attrition and Proposed Attrition Changes	David S. Thomason
11	Ch. 3	Rate Base Growth in Attrition Years and Related	Charles M. Marre
12		**Statements of Qualifications**	All