ATTACHMENT A

(ATTACHMENT A)

SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY, OFFICE OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, AGLET CONSUMER ALLIANCE, MODESTO IRRIGATION DISTRICT, THE NATURAL RESOURCES DEFENSE COUNCIL AND THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

In accordance with Rule 51.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), Aglet Consumer Alliance (Aglet), Modesto Irrigation District (MID), the Natural Resources Defense Council, and the Agricultural Energy Consumers Association (AECA) (collectively, the "Settling Parties") hereby enter into this Settlement Agreement (the "Agreement") to resolve all but one disputed issue among the Settling Parties in the revenue requirement phase of PG&E's forecast test year 2003 General Rate Case (GRC), Application 01-11-017. The one issue not resolved by this Agreement, pension contribution funding, is discussed below. The Settling Parties also agree that this Agreement may not resolve disputed issues raised by other parties. The Settling Parties further agree that PG&E's GRC revenue requirements will be adjusted upon decision of the Commission on those issues remaining for briefing.

MID joins only in paragraph 26 of the "Recitals," Sections 3.3.3 and 4.10 of the "Settlement Agreement," all of the "Reservations," and Appendix A of this Agreement. NRDC joins only in paragraph 25 of the "Recitals," Sections 4.6 and 4.11 of the "Settlement Agreement," and all of the "Reservations." MID and NRDC take no position on the other provisions of this Agreement.

RECITALS

Procedural History

1. On November 8, 2002, PG&E filed its 2003 GRC Application. On January 28, 2003, and May 21, 2003, the Commission convened prehearing conferences.

2. On February 13, 2003, Assigned Commissioner Michael P. Peevey issued an "Assigned Commissioner's Ruling Establishing Scope, Schedule, and Procedures for Proceeding" (ACR) calling for hearings to begin on May 28, 2003, with a final Commission decision to be issued by February 5, 2004. The ACR directed PG&E to host a meeting to develop procedural recommendations regarding how issues surrounding the Diablo Canyon Independent Safety Committee should be addressed. The ACR also directed PG&E to serve revised testimony to remove aspects of the generation revenue requirement that the Commission stated would be addressed through the Energy Resource Recovery Account.

3. In response to PG&E's request, the ACR further provided that the issue of recovery of costs associated with the delay in implementing PG&E's new Customer Information System (CIS) required to implement the 2002 "20/20" program is within the scope of the GRC and directed parties to address both the reasonableness of the costs and whether ratepayers or the Department of Water Resources are to pay these costs.

4. The ACR ordered PG&E to address several issues in PG&E's March 17, 2003 supplemental testimony, including: (1) storm and reliability performance issues; (2) workforce diversity; (3) compliance with Public Utilities Code Section 739.10; (4) a Results of Operations (RO) exhibit to incorporate 1999 authorized and recorded data; and (5) an "Illustrative Rate Showing" consistent with the Commission's Energy Division finding regarding public purpose program rates. In addition, the ACR directed PG&E, by April 7, 2003, to serve testimony

regarding integrated resource planning, in which PG&E "should assume that it will remain a vertically integrated utility responsible for procuring and providing resources to its customers and should identify the costs of staffing and supporting this responsibility."

5. In response to the ACR, PG&E served supplemental testimony on these issues, which was admitted during the subsequent evidentiary hearings.

6. On April 11, 2003, ORA served its testimony in response to PG&E's November 8, 2002, Application. TURN, Aglet and other intervenors served their testimony on May 2, 2003, with TURN serving testimony on depreciation-related issues on May 30, 2003. Settling Parties and other intervenors served rebuttal testimony on May 22, 2003, with PG&E serving rebuttal testimony on TURN's depreciation-related testimony on June 19, 2003.

7. Evidentiary hearings began on May 28, 2003, and continued through July 29. On July 30, PG&E, ORA, TURN and Aglet began a series of settlement discussions pursuant to Rule 51. On September 2, 2003, as required by Rule 51.1(b), PG&E notified all parties on the service list of a settlement conference to be held on September 9, 2003 to discuss the terms of the Agreement.

8. On July 31, 2003, PG&E, ORA, TURN, Aglet and the City and County of San Francisco (CCSF) filed a separate settlement resolving disputed issues regarding the forecast test year 2003 generation revenue requirements and 2004, 2005, and if applicable, 2006 attrition adjustments (the "Gen Settlement"). Generally, the Gen Settlement sets a 2003 generation revenue requirement of $955 million and provides for attrition adjustments based on the Consumer Price Index (CPI), plus specific cost items such as the costs of increased security requirements and refueling outage adjustments at the Diablo Canyon Nuclear Power Plant (Diablo Canyon).

9. The Gen Settlement acknowledges that the generation revenue requirement will change upon final execution of the Results of Operations (RO) model, to reflect the final determination and allocation of Administrative and General (A&G) expense and common plant, and due to the resolution of certain tax-related issues not specifically addressed or resolved in the Gen Settlement, including those issues raised by recent revisions to the U. S. tax code. Once this Agreement is approved, and the Commission decides the pension issue, the Gen Settlement will be adjusted accordingly.

10. Following the settlement conference, the Settling Parties signed this Agreement on Monday, September 15, 2003.

Summary Of Settling Parties' Litigation Positions

PG&E's Application

11. In its November 8, 2002 Application, PG&E proposed overall forecast test year 2003 electric and gas distribution revenue requirements of $2,716 million and $1,000 million, respectively, which, based upon then current authorized revenues, would result in increases of $447 million in electric distribution revenues and $105 million in gas distribution revenues. Concurrent with its filing for revenue requirement increases for its test year 2003 electric and gas distribution operations, PG&E also sought attrition year revenue requirement increases in 2004 and 2005. PG&E proposed that attrition year increases would be updated just prior to each attrition year, based upon current escalation and other information. PG&E estimated its attrition year increases at $64 million in 2004 and $85 million in 2005 for its electric distribution operations and $26 million for 2004 and $32 million for 2005 for its gas distribution operations. In its February 20, 2003, update pursuant to the ACR, PG&E requested a total 2003 generation revenue requirement of $1,022 million, representing a $149 million increase over the authorized

2002 revenue requirement and forecast generation attrition changes for 2004 and 2005 of a $33.7 million increase and a $39.3 million decrease, respectively.

PG&E's Comparison Exhibit Position

12. At the conclusion of hearings, PG&E served the Comparison Exhibit (Exhibit 100 and errata) that summarizes the revenue requirement positions of PG&E, ORA, and other parties as of August 8, 2003.

13. As a result of supplemental testimony served in response to the ACR and correction of errors and adjustments associated with concessions PG&E made during the course of the hearing and in the preparation of the Comparison Exhibit, PG&E's pre-Agreement litigation position would result in base revenue requirements for PG&E's electric and gas distribution functions of $2,710 million and $982 million, respectively, resulting in increases over currently authorized revenues of $453 million for electric distribution service and $97 million for gas distribution service. PG&E's litigation position would result in 2004 and 2005 estimated attrition increases of $74 million and $83 million for electric distribution and $28 million and $31 million for gas distribution.

14. PG&E did not oppose ORA's position that the test year for PG&E's next GRC be 2007, rather than 2006, and, if so adopted by the Commission, proposed that it be permitted to file for attrition relief by advice letter in 2006 or by a supplemental application for an incremental amount if the revenues produced by the Attrition Rate Adjustment (ARA) mechanism are insufficient to provide PG&E a reasonable opportunity to earn its authorized rate of return. PG&E's forecast 2006 attrition revenue requirement set forth in the Comparison Exhibit is $82 million for electric distribution and $31 million for gas distribution.

15. In the Comparison Exhibit, PG&E requested that the Commission adopt a total

generation revenue requirement of $944 million, representing a $70 million increase over the authorized 2002 revenue requirement. PG&E estimated generation attrition increases of $59 million, $(9) million and $34 million for 2004, 2005 and 2006, respectively. PG&E's position, as of the Comparison Exhibit, was based on the Gen Settlement, as adjusted to reflect PG&E's litigation position on issues not resolved in the Gen Settlement.

16. As set forth below, PG&E has, as part of an overall settlement, compromised significantly on these amounts.

ORA's Comparison Exhibit Position

17. On April 11, 2003, the ORA served its written testimony. Based upon this prepared testimony, as modified by the Gen Settlement and adjusted to correct for certain errors and to reflect concessions made during the hearing, ORA's pre-Agreement litigation position reflected in the Comparison Exhibit recommends a total 2003 revenue requirement of $2,446 million for electric distribution, $909 million for gas distribution and $895 million for generation, resulting in increases, respectively, of $189 million, $34 million, and $21 million over currently authorized electric and gas distribution and generation-related revenues.

18. Regarding attrition, ORA would permit PG&E to file an advice letter seeking distribution attrition relief based upon a traditional formula that ORA estimated would result in increases of $68 million, $88 million and $86 million, respectively, for electric distribution in 2004, 2005 and 2006 and $20 million, $28 million and $28 million in 2004, 2005 and 2006 for gas distribution. ORA also proposed that PG&E be allowed, if it so chose, to submit an application (rather than an advice letter) for 2006 attrition if the ARA mechanism did not allow PG&E a reasonable opportunity to earn its authorized rate of return.

19. For generation attrition, ORA's Comparison Exhibit position was based upon the

Gen Settlement and ORA's recommendation regarding the underlying total revenue requirement, resulting in illustrative attrition increases of $58 million, $(10) million and $32 million for 2004, 2005, and 2006, respectively.

20. ORA's current litigation position, as set forth in the Comparison Exhibit, reflects significant decreases to PG&E's forecast of A&G expenses, as well as to forecasts of electric distribution Operations and Maintenance (O&M) expenses, Customers Accounts expenses, Information Technology costs, income tax expenses, electric, gas and common plant, depreciation, and rate base and increases to Other Operating Revenues.

21. Regarding depreciation, ORA would keep unchanged the net salvage percentages that the Commission established in PG&E's 1996 GRC for the electric distribution function. ORA would accept PG&E's proposed net salvage percentages in this GRC for the gas distribution function, which results in negative net salvage percentages that are lower (i.e., more positive and therefore less negative) than those the Commission established in PG&E's 1996 GRC for the gas distribution function. ORA did not oppose PG&E's proposed average service lives for the electric and gas distribution functions.

22. ORA also set forth a number of recommendations regarding PG&E's existing Quality Assurance Program guarantees and other customer service related issues. ORA also addressed planning and budgetary processes, major work category descriptions, time sheet retention, and mapping issues.

TURN's Position

23. TURN was an active party throughout the proceeding. It made a number of recommendations, including reductions to PG&E's forecasts for its CIS, A&G expenses, distribution O&M expenses and Customer Accounts and Services expenses. TURN also

proposed several adjustments to working cash; proposed changes to PG&E's method of accounting for costs associated with new customer connections; asserted that PG&E should collect additional data related to new customer connections; recommended a different method of charging a fee to customers who pay their PG&E bill with checks backed by insufficient funds; and suggested that PG&E explore alternatives with the service provider PG&E uses to administer payments with a credit or debit card in order to achieve lower fees. TURN also challenged numerous aspects of PG&E's depreciation study. TURN differed from PG&E on depreciation issues on net salvage values and, to a lesser extent, average service lives.

Aglet's Position

24. Aglet was also an active party throughout the GRC proceeding. Aglet made several proposals, including recommendations to increase estimated joint pole receipts, reduce estimated meter reading expenses, deny rate recovery of customer retention and economic development expenses, and adopt an uncollectibles factor of 0.182 percent. Aglet also proposed that PG&E be authorized to file an application for only one year of attrition relief (2005) based on the CPI. In addition, Aglet recommended that PG&E not be assigned primary responsibility for integrated electric resource planning.

NRDC's Position

25. NRDC's testimony focused on how PG&E and this Commission should meet the requirements of Public Utilities Code Section 739.10 and ensure that its revenue be independent of the level of sales. NRDC recommended a single revenue adjustment mechanism and balancing account, encompassing the recovery of all of PG&E's non-fuel GRC-related revenues, to be created separate from the Transition Revenue Account (TRA) to ensure a smooth transition at the time the TRA ends. NRDC recommended that this mechanism track actual revenues

compared to PG&E's Commission-approved revenue requirement and make periodic true-ups to adjust for over- or under-collections to comply with Section 739.10. In addition, in response to Aglet's testimony on integrated resource planning, NRDC noted that state law places the responsibility for integrated resource portfolio management with the utilities, and recommended that the Commission continue to provide strong policy guidance and oversight.

MID's Position

26. MID was primarily interested in two matters, customer retention and idle facilities, and presented testimony on both. MID's testimony focused on whether PG&E could adequately demonstrate the benefits to ratepayers of its proposed customer retention program. MID also presented testimony with regard to certain safety and reliability aspects of PG&E's current practice of maintaining in place its distribution facilities even though such facilities are not presently serving customers, generally as a result of customer departure from PG&E electric service.

SETTLEMENT AGREEMENT

As a compromise among their respective litigation positions, and subject to the Recitals and Reservations set forth in this Agreement, the Settling Parties hereby agree that this Agreement resolves all disputed issues raised in this General Rate Case by the Settling Parties, with the exception of the pension contribution funding issue discussed below and set for briefing.

The Settling Parties agree that this Agreement may not resolve disputed issues raised by other parties. The Settling Parties further agree that PG&E's GRC revenue requirements will be adjusted upon decision of the Commission on those issues remaining for briefing.

The Agreement is presented to the Commission pursuant to Rule 51 of the Commission's Rules of Practice and Procedure.

1. **2003 Distribution Revenue Requirement**

The Settling Parties agree that, for the issues resolved in this Settlement, a 2003 revenue requirement of approximately $2,493 million electric distribution and $927 million gas distribution ($2003) is reasonable. These amounts reflect revisions from PG&E's request in the Comparison Exhibit of approximately $2,710 million electric distribution and $982 million gas distribution as detailed below, and do not include revenue requirements for those issues not settled.

The Settling Parties agree that PG&E's revenues at present rates are $2,257.344 million electric distribution and $874.895 million gas distribution. This Agreement results in an increase from present rates of approximately $236 million electric distribution, and $52 million gas distribution. This represents an increase of 10.44% in PG&E's electric distribution revenues (excluding energy), and 5.90% in PG&E's gas distribution revenues. This compares to PG&E's requests (in the Comparison Exhibit) of an increase in revenues of 20.07% electric distribution and 12.28% gas distribution. A portion of the increase in distribution revenues is collected as other operating revenues, rather than from sales of electricity and gas. The increase in revenues from sales to customers resulting from this Agreement is 8.46% electric distribution and 4.60% gas distribution, as compared to PG&E's requests (in the Comparison Exhibit) of 18.23% electric distribution and 10.88% gas distribution.

2. **2003 Generation Revenue Requirement**

The Settling Parties agree that, for the issues resolved in this Agreement (as well as the issues resolved in the Gen Settlement) a 2003 generation revenue requirement of approximately $912 million ($2003) is reasonable. This amount reflects reductions from the Gen Settlement associated with A&G expense, common plant, and tax issues, as detailed below. PG&E's

generation request in the Comparison Exhibit was approximately $944 million.

The Settling Parties agree that PG&E's revenues at present rates are $874.264 million for generation. This Agreement, together with the Gen Settlement, results in an increase from present rates of approximately $38 million. This represents an increase of 4.35 percent in PG&E's generation revenues (excluding energy). This compares to PG&E's request (in the Comparison Exhibit) of an increase in revenues of 7.95 percent. A portion of the increase in generation revenues is collected as Other Operating Revenues, rather than from sales of electricity. The increase in revenues from sales to customers resulting from this Agreement is 3.90 percent, as compared to PG&E's request (in the Comparison Exhibit) of 7.51 percent.

3. Description Of Revisions To Forecast 2003 Revenue Requirement

3.1 Administrative and General (A&G) Expense

3.1.1 A&G Expense

The Settling Parties agree that PG&E's A&G expenses will be reduced to $585 million ($2000 total utility). (This compares to the $735.767 million in PG&E's position in the Comparison Exhibit, Exhibit 100, p. 24.)

3.1.2 Pension Contribution

PG&E's pension contribution request is not settled. It will be briefed by the Settling Parties. This Agreement's amount for A&G expense does not include a pension contribution. This Agreement does include an amount for net wage-related pension expense of $1.7 million ($2000 total utility). Any amount the Commission authorizes for pension contribution will be incorporated in PG&E's revenue requirements.

3.1.3 Capitalization Rates for A&G

The Settling Parties agree capitalization rates for those A&G items that are capitalized in

the following accounts are as follows:

Account 920: Performance Incentive Plan Capitalization	24.0	%
Account 920: Salaries	10.9	%
Account 921: Office Supplies (All)	7.6	%
Account 923: Outside Services (All)	1.9	%
Account 925: Workers Compensation	32.22	%
Account 925: Third Party Claims	19.9	%
Account 926: Pension and Benefits	32.22	%

3.1.4 A&G Allocation to Non-GRC UCCs

The Settling Parties agree that it is more efficient to litigate common costs like A&G only once, in the GRC, and then to use the results in other CPUC proceedings, rather than re-litigating these common A&G costs multiple times. The Settling Parties agree that the A&G expenses allocated to the Unbundled Cost Categories (UCCs) adopted in this 2003 GRC should be used in determining the A&G expenses in related proceedings in 2003 and future years until the 2007 test year GRC, if the outcome of those proceedings would otherwise require specific calculation of A&G expenses. Specifically, the UCCs and related proceedings are: Gas Transmission (Gas Accord II and Gas Accord III), Humboldt (Nuclear Decommissioning Cost Triennial Proceeding), Gas public purpose programs (PPP) and Electric PPP. To the extent that Commission decisions in 2004 through 2006 on PPP include less A&G expense than the amounts allocated to PPP UCCs in this Agreement, any shortfall will be recovered through GRC distribution attrition revenues.

3.1.5 Nuclear Decommissioning Trust Fund Fees

In this GRC, $2.97 million of administrative fees for nuclear decommissioning trust fund A&G (Account 930 - Miscellaneous General Expenses) has been allocated to the generation UCCs. The Settling Parties agree that in its next Nuclear Decommissioning Cost Triennial Proceeding Application, PG&E will include these costs as a nuclear decommissioning expense

and reduce the generation revenue requirement by an equal amount as set forth in the Joint Recommendation of TURN and PG&E in Exhibit 426.

3.2 Operations & Maintenance (O&M) Expense

3.2.1 Distribution O&M Expense

The Settling Parties agree that PG&E's distribution O&M expenses ($2000 FERC) will be $391.5 million electric and $118.5 million gas. (This compares to the $399.873 million electric and $119.940 million gas in PG&E's position in the Comparison Exhibit.)

3.2.2 Vegetation Management Expense

The Settling Parties agree Vegetation Management expense (included in the above electric total) will be $124.7 million. (This compares to the $126.857 million request in PG&E's Comparison Exhibit, Ex 100 page C-2) This amount includes funding for the Vegetation Management Quality Assurance Program, incorporating the assumption that shareholders do not share in the forecast cost of this program. The one-way balancing account for Vegetation Management and the associated Quality Assurance Plan will continue in effect, as will the tree removal program.

3.3 Customer Accounts and Services Expense

3.3.1 Customer Accounts Expense

The Settling Parties agree that PG&E's distribution Customer Accounts expenses ($2000 FERC) will be $199.9 million electric and $154.7 million gas. (This compares to the $206.025 million electric and $159.492 million gas in PG&E's position in the Comparison Exhibit.)

3.3.2 Line Extension Administration

The Settling Parties agree that the Customer Accounts expenses set forth in Section 3.3.1 include, but are not limited to, the following changes in PG&E's administration of the line

extension process:

- Main Line Extension (MLX) processing expenses incurred in 2004 and subsequent years will be charged to new customer connection applicants in a manner to be determined by PG&E.
- Non-residential customer revenue estimating expenses incurred in 2004 and subsequent years will be charged to new customer connection applicants in a manner to be determined by PG&E.
- New customer connection process improvement expense incurred in 2004 and in subsequent years will be included in the overheads charged to all new application projects.

3.3.3 Customer Services Expense

The Settling Parties agree that PG&E's distribution Customer Services expenses ($2000 FERC) will be $1.363 million electric and $3.483 million gas ($2000). This reflects zero expense in the Account 912 revenue requirement for customer retention and economic development. (This compares to the $3.662 million electric and $3.618 million gas in PG&E's position in the Comparison Exhibit.)

3.4 Uncollectibles

The Settling Parties agree to reduce the factor used to calculate uncollectibles expense from PG&E's proposed 0.25 percent to 0.20 percent.

3.5 Other Production Expense

The Settling Parties agree that PG&E's electric Other Production expense will be $16.6 million, and that PG&E's electric transmission O&M expense will be $0.552 million, and that

PG&E's gas Other Production expense will be $3.356 million gas ($2000 FERC). (This compares to the $22.446 million, $0.552 million, and $3.356 million, respectively, in PG&E's position in the Comparison Exhibit.)

3.6 Depreciation Method

The Settling Parties agree to the depreciation parameters resulting from ORA's position on electric, gas, and common plant depreciation.

3.7 Rate Base

The Settling Parties agree to use recorded 2002 plant as the starting point for calculating test year 2003 rate base. The Settling Parties agree to allocate residual common plant and depreciation reserve using the allocation method presented in PG&E's rebuttal testimony and implemented in the Comparison Exhibit. (Ex. 24, pp. 6-1 to 6-17 and Ex. 24A, p.6-8 and Tr. 3149:16-19, ORA/Harpster.)

3.8 Capital Additions

The Settling Parties agree that net weighted average capital additions for 2003 ($2003) will be $292 million for the electric distribution UCCs and $89.2 million for the gas distribution UCCs. (This compares to the $351.335 million for the electric distribution UCCs and $107.767 million for the gas distribution UCCs in PG&E's position in the Comparison Exhibit.)

The above net capital additions reflect a 2003 forecast for joint pole receipts (representing the joint pole owner's share of capital projects) of $21 million. (This is $4.1 million higher than PG&E's forecast.)

The above net weighted average capital additions for 2003 assume incorporation of higher capitalization rates for A&G and reflect an allocation of net weighted average additions for common, general and intangible plant of $17.5 million for the electric distribution UCCs and

$10.9 million for the gas distribution UCCs. The allocation of net weighted average additions for common, general and intangible plant for the generation UCCs will be $7.79 million. (These are identical to PG&E's position in the Comparison Exhibit, adjusted for the errata 100-B.)

3.9 Working Cash

The Settling Parties agree to reduce working cash by $63 million electric and $37 million gas ($2003) relative to PG&E's position set forth in the Comparison Exhibit. (Exhibit 100, pages 2-11 and 2-22.)

3.10 Tax Method

The Settling Parties agree that PG&E's method for calculating vehicle clearing depreciation will be used, including PG&E's errata. (Ex. 24, pp 1-7 to 1-10.)

The Settling Parties agree to recognize the current year deduction for capitalized A&G overheads for the calculation of test year income taxes.

The Settling Parties agree that the effect of 50 percent bonus depreciation, a change in the tax code as of May 2003, will not be recognized for the calculation of test year 2003 income taxes.

4. Other Issues

4.1 Franchise Fee Factors

The Settling Parties agree that the factors used to calculate franchise fees will be 0.007541 (electric) and 0.009673 (gas).

4.2 O&M Labor Factors

The Settling Parties agree that O&M labor factors will be calculated from 2002 recorded adjusted O&M labor. (Ex. 100-B, page F-45.)

4.3 Other Operating Revenues

The Settling Parties agree CPUC-jurisdictional Other Operating Revenues will be $67.3 million electric and $16.3 million gas ($2003). (This compares to the $65.004 million electric and $15.992 million gas in PG&E's position in the Comparison Exhibit.)

4.4 Balancing Accounts for New Customer Connection and E-Net Costs

The Settling Parties agree that recovery of the costs of new customer connections and E-Net will not be protected by balancing accounts.

4.5 Insufficient Funds Fee

The Settling Parties agree that the insufficient funds (NSF) fee for returned checks will be increased from the current $6 to $8.

4.6 Public Utilities Code Section 739.10

The Settling Parties agree that the Distribution Revenue Adjustment Mechanism (DRAM) and Utility Generation Balancing Account (UGBA) balancing accounts will be implemented as revenue adjustment mechanisms effective January 1, 2004 to ensure that PG&E recovers its authorized electric distribution and electric generation revenue requirements regardless of the level of sales.

4.7 Recovery of Expenses Associated With 20-20 Program

The Settling Parties agree to allow recovery of the revenue requirement associated with $7.3 million in 2002 expenses incurred to implement the 20-20 program. PG&E will initially recover this revenue requirement from ratepayers by a debit entry to DRAM. The Settling Parties agree that DWR is ultimately responsible for these costs. PG&E will bill DWR the same amount debited to DRAM, and credit funds received from DWR to DRAM.

4.8 CIS Capital

The Settling Parties agree that there will be a further $7 million credit against the revenue requirement (which will be allocated among PG&E's functions using the allocation method for the CIS system), to fully resolve TURN's recommended CIS capital disallowance. The $7 million adjustment extends through 2006 under the attrition method in this Agreement. PG&E will retain the capital in rate base and continue depreciation using the applicable depreciation schedule for CIS. In the 2007 GRC, PG&E will include the remaining undepreciated balance of this capital in rate base.

4.9 Idle Facilities -- Accounting/Ratemaking Issues

The Settling Parties agree that PG&E will include in its next GRC a showing on the plant and depreciation accounting transactions associated with the life cycle of distribution assets and the requirements of the Uniform System of Accounts and other applicable accounting standards. This showing shall include, at a minimum, a description of PG&E's current practices and the basis for those practices.

4.10 Idle Facilities – Removal

The Settling Parties agree that Appendix A sets forth the agreement of the Settling Parties regarding removal of idle facilities.

4.11 Integrated Resource Planning

The February 13, 2003 "Assigned Commissioner's Ruling Regarding Scope, Schedule and Procedures for Proceeding" directed PG&E to identify costs of staffing associated with an assumption that PG&E "will remain a vertically integrated utility responsible for procuring and providing resources to its customers ..." PG&E submitted testimony regarding costs relating to integrated resource planning, not including any activities associated with construction or project

management of new generation. The Settling Parties understand that the Commission is considering integrated resource and procurement issues in R.01-10-024 and that the Commission will further define PG&E's role in this area which may affect costs. The Settling Parties reserve their rights to address such issues in other proceedings, as the role of utilities in this area is further developed by the Commission.

4.12 Service Guarantees under the Quality Assurance Program and Customer Service Issues

Appendix B sets forth the agreement of the Settling Parties regarding service guarantees under the Quality Assurance Program and other customer service related issues.

4.13 Accounting, Data Collection, and Reporting Issues

Appendix C sets forth the agreement of the Settling Parties regarding various accounting, data collection, and reporting issues.

4.14 Withdrawal of Testimony

As part of this Agreement, PG&E agrees to withdraw the testimony of M. Christie McManus, including errata and workpapers, set forth in PG&E Exhibits 19, 19-A, 19-B and 19-1W, and her statement of qualifications set forth in Exhibit 27 at pages MCM-1 and MCM-2, and Transcript 2082:18 through 2083:25 and 2252:7 through 2258:13. In addition, the Settling Parties agree to withdraw their cross examination of Ms. McManus, set forth at Transcript 2083:27 through 2243:16 and 2261:8 through 2270:24 and their cross examination exhibits related to Ms. McManus' testimony, Exhibits 337, 338, 339, and 561.

4.15 Uncontested Issues

Appendix D sets forth the agreement of the Settling Parties regarding various uncontested issues.

5. Attrition Years

5.1 2007 Test Year GRC

The Settling Parties agree to deferral of PG&E's next GRC until test year 2007 and the addition of an attrition adjustment for 2006.

5.2 Attrition Authorized for Implementation by Advice Letter

The Settling Parties agree that attrition relief for 2004, 2005, and 2006 will be authorized in this GRC, and implemented by advice letter.

5.3 Attrition Mechanism

The Settling Parties agree that PG&E's annual distribution attrition adjustment for 2004 and 2005 will be equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers. PG&E's annual distribution attrition adjustment for 2006 will be equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers, plus one percent.

Notwithstanding the forecast change in CPI-All Urban Consumers, the minimum and maximum revenue requirement adjustments will be as follows:

	2004	2005	2006
Minimum	2.0%	2.25%	3.0%
Maximum	3.0%	3.25%	4.0%

The CPI change equals the latest Global Insight forecast prior to filing (for example October 2003, for year 2004) divided by the concurrent forecast for the current year (for example October 2003, for year 2003), minus one.

5.4 Cost of Capital Proceedings

The Settling Parties agree that outcomes in future Cost of Capital proceedings could

affect PG&E's revenue requirement, including the attrition adjustment settled herein.

RESERVATIONS

1. This Agreement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

2. The fact that the Settling Parties set forth specific amounts for certain categories of costs is not intended to limit PG&E's management discretion to spend funds as it sees fit and consistent with its obligation to serve.

3. The Settling Parties agree that this Agreement represents a compromise, not agreement or endorsement of disputed facts and law presented by the Settling Parties in the 2003 GRC.

4. The Settling Parties shall jointly request Commission approval of this Agreement. The Settling Parties additionally agree to actively support prompt approval of the Agreement. Active support shall include briefing, comments on the proposed decision, written and oral testimony if testimony is required, appearances, and other means as needed to obtain the approvals sought. The Settling Parties further agree to participate jointly in briefings to Commissioners and their advisors as needed regarding the Agreement and the issues compromised and resolved by it.

5. This Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations or understandings among the Settling Parties.

6. The Agreement may be amended or changed only by a written agreement signed

by the Settling Parties.

7. With the exception of the agreement reached on PG&E'S Safety Net Program, this Agreement is independent of and separate from the performance, reporting, and revenue issues contained in the storm and reliability performance phase of this 2003 GRC.

8. The Settling Parties have bargained earnestly and in good faith to achieve this Agreement. The Settling Parties intend the Agreement to be interpreted and treated as a unified, interrelated agreement. The Settling Parties therefore agree that if the Commission fails to approve the Agreement as reasonable, and adopt it unconditionally and without modification, including the findings and determinations requested herein, any Party may, in its sole discretion, elect to terminate the Agreement. The Settling Parties further agree that any material change to the Agreement shall give each Party, in its sole discretion, the option to terminate the Agreement. In the event the Agreement is terminated, the Settling Parties will request that the unresolved issues in Application 02-11-017 be heard and briefed at the earliest convenient time.

9. This Agreement represents a compromise of respective litigation positions and is not intended to establish binding precedent for any future proceeding. The Settling Parties have assented to the terms of this Agreement only for the purpose of arriving at the compromise embodied herein.

10. Each of the Settling Parties hereto and their respective counsel and advocates have contributed to the preparation of this Agreement. Accordingly, the Settling Parties agree that no provision of this Agreement shall be construed against any Party because that Party or its counsel drafted the provision.

11. This document may be executed in counterparts, each of which shall be deemed

an original, but all of which together shall constitute one and the same instrument.

12. This Agreement shall become effective among the Settling Parties on the date the last Party executes the Agreement as indicated below.

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

Appendix A
Removal of Idle Facilities

Within the area defined in Public Utilities Code Section 9610(b)(1) as within both PG&E's and Modesto Irrigation District's electric service area, PG&E shall work to remove any Facilities Identified for Removal, as defined below, working with the affected property owner.

For purposes of this proceeding, "Facilities Identified for Removal" shall mean:

(a) an overhead distribution line or an easily severable portion of an overhead distribution line,

(b) located on private property;

(c) that serves a single customer;

(d) which customer's obligations under any applicable Distribution and Service Agreement or Agreement for Installation or Allocation of Special Facilities have been met, and,

(e) PG&E has determined that the overhead distribution line or easily severable portion of an overhead distribution line Does Not Have Any Forseeable Future Use.

For purposes of this proceeding, Does Not Have Any Forseeable Future Use shall mean:

(1) the overhead distribution line, or portion of an overhead line, is no longer being used to serve PG&E retail customer load because the customer previously served by the line or portion of line has been receiving retail electric distribution service from a local publicly owned electric utility, as defined in Public Utilities Code Section 9604, for at least twelve consecutive months, and,

(2) PG&E has determined that the overhead line, or portion of an overhead line, is not needed for future capacity, service reliability or to serve other customers, either now or in the foreseeable future, and,

(3) PG&E has determined, after consultation with the former customer and, if the customer is a tenant, the property owner, that neither of them intends to seek PG&E electric distribution service for at least twenty-four months in the future or after the expiration of the customer's current agreement with the other utility, whichever is later.

This agreement shall expire on December 31, 2006, unless extended or terminated by mutual agreement of PG&E and MID.

Appendix B
Service Guarantees under the Quality Assurance Program and Customer Service Issues

1. The Settling Parties agree that existing QAP standard No. 2 shall be reworded to provide as follows:

   Investigate non-emergency situations (check meter) and communicate results to customers within 7 days of a customer request.

2. The Settling Parties agree to eliminate QAP standard No. 3, which deals with PG&E's response to requests for emergency service.

3. The Settling Parties agree that QAP standard No. 4 shall be reworded to provide as follows:

   Decide on a course of action to resolve a complaint and communicate it to the customer within 3 working days, and communicate the complaint's resolution to the customer within 10 working days, or 30 working days when an off-site meter test is required or an on-site home audit is requested.

4. The Settling Parties agree that a new QAP standard (QAP standard No. 3) shall be added that provides as follows:

   PG&E shall provide at least 3 days notice of a planned interruption in service.

5. The Settling Parties agree that a new QAP standard (QAP standard No. 8) shall be added that provides as follows:

   PG&E shall issue an accurate first bill to a new customer account within 60 days of service initiation.

6. The Settling Parties agree that the reports PG&E currently submits to the Commission regarding its QAP on a monthly basis, shall, beginning with the end of the first quarter in which the Commission approves this Agreement, thereafter be submitted on a quarterly basis.

7. The Settling Parties agree that the quarterly reports described in the immediately preceding paragraph shall provide information on a division-by-division basis as well as on a system-wide basis.

8. ORA and PG&E agree that they will work together and with other interested parties, in workshops, to develop auditable tracking and reporting requirements for the QAP to ensure that reports contain the information reasonably necessary to evaluate PG&E's performance in the areas that QAP covers, including the feasibility of providing text explaining any factors that lead to significant variations in the number of claims over time and location.

9. The Settling Parties agree that the credit given to customers when PG&E fails to comply with a QAP standard shall be $30 for each QAP standard except QAP standard No. 5, which pertains to an agreed upon date with the customer for installing a new meter and

initiating service; the credit for QAP standard No. 5 shall be $50.

10. The Settling Parties agree that the "Safety Net Program," which PG&E voluntarily adopted in March 2003, shall become mandatory in its entirety, and without alteration. This Agreement resolves all issues raised in the Storm and Reliability Performance Phase of the 2003 GRC regarding PG&E's Safety Net Program, and supersedes the positions taken by PG&E and ORA on this Program.

11. The Settling Parties agree that PG&E shall provide quarterly reports to the Commission on the Safety Net Program. These reports will be similar to the reports described in paragraphs 6-8 above for the QAP program, and PG&E will work with other parties in workshops to ensure that the reports contain the information reasonably necessary to evaluate PG&E's performance under the Safety Net program.

12. The Settling Parties agree that nothing in this Agreement shall preclude ORA from recommending changes to PG&E's QAP or Safety Net Program in an Order Instituting Investigation, or in PG&E's next GRC.

13. PG&E agrees to follow up on the "Network Study" performed for PG&E by Verdi & Company as discussed in Chapter 9-A of Exhibit 303.

14. The Settling Parties agree that PG&E's practice shall be to process payments made at drop boxes by 2 p.m. on the day such payments are made, but PG&E's failure to process such payments on the day of deposit shall not be a violation of this Agreement.

15. PG&E agrees to develop surveys of customers who patronize PG&E's local offices and its pay stations to ascertain customer satisfaction with the quality of PG&E's service at these pay locations.

16. PG&E will continue to explore retention efforts for customer service representatives and will report on such efforts in its next GRC.

17. PG&E will investigate whether to implement technology improvements and/or process changes to enhance communications between call center and field employees and report its findings in its next GRC.

18. PG&E will conduct a survey to determine if its translation service is meeting the needs of the various Asian/Pacific Islander communities and report its finding in its next GRC.

19. PG&E also agrees to submit a midpoint report to ORA on June 30, 2005 describing its efforts to that date pertaining to Items 16, 17 and 18 above.

20. PG&E will file an annual report with the Commission and ORA that describes and evaluates efforts to improve its website. The report will be filed on April 1 each year, beginning in 2004.

21. PG&E will explore alternatives for securing lower fees for customers who chose to pay their PG&E bills via debit or credit card when its contract expires with Bill Matrix on May 31, 2004. (Ex. 403, p.25)

Appendix C
Accounting, Data Collection, and Reporting Issues

1. **Time Sheets**
   In its next GRC, PG&E will provide to ORA any available time sheets for the recorded years 2004 and 2005. This assumes that PG&E's next GRC has a 2007 test year and that the base recorded year for the case is 2004. (Ex. 308, p. 5-3)

2. **Planning and Budgeting Process Documentation**
   In its next GRC, PG&E agrees to provide documentation of its planning and budgeting processes, including a description of the criteria used to evaluate and prioritize distribution capital projects. PG&E also agrees to provide a comparison of recorded distribution capital expenditures to its approved budget. If PG&E presents its case by MWC, this comparison will be provided by MWC. (Ex. 304B, p. 14-28.)

3. **Pole Replacement or Reinforcement Records**
   PG&E agrees to maintain and provide (in a data base or comparable format to be agreed upon by PG&E and ORA) the following records and information pertaining to poles identified in need of replacement or reinforcement: (1) the date the pole is identified as a candidate for replacement, (2) the date by which PG&E expects to replace the pole, and (3) the actual replacement date.

4. **Major Work Category Information**
   In its next GRC, if PG&E presents its case by MWC, PG&E will present five years of capital MWC information (i.e., years 2000 to 2004) on a consistent, historical basis. If PG&E presents its case by MWC, PG&E will also provide expense MWC information on a consistent, historical basis beginning with 2004 recorded data. PG&E will describe any changes in MWC definitions and explain its estimating techniques used to present the data on a consistent basis. (Ex. 304B, p. 14-32).

5. **Changes in Accounting Methods**
   In its next GRC, PG&E agrees to explain any significant changes in its accounting methods that have occurred since the 2003 GRC, including a description of any decision to capitalize major items or functions that were previously expensed and/or expense items or functions that were previously capitalized. The description will include the reasoning supporting such changes. "Significant" means items of more than $1 million.

6. **Mapping Improvement Program**
   PG&E will submit to the Commission and ORA an annual report detailing the progress of Phase II of its Mapping Improvement Program. The first report will be due on April 1, 2004, and subsequent reports will be filed on the same date each subsequent year until the project is completed.

7. **Line Extension Data Collection**
   - PG&E will develop the databases and track the information contained in Attachment B to Exhibit 402, and provide an annual report to the Commission on the status and progress of its data collection on new customer connections.
   - PG&E will complete development and implementation of the databases by December 31, 2004, and begin tracking the information on January 1, 2005.
   - PG&E will not be required to consolidate the information contained in Attachment B to Exhibit 402 for new customer applications received prior to January 1, 2005.

Appendix D
Uncontested Issues

The following issues were either uncontested or were resolved by the Settling Parties prior to the filing of the Comparison Exhibit such that they were uncontested at the end of hearings.

1. Forecasts of Customers and Sales

The Settling Parties agree to the electric and gas billings and sales forecasts set forth in the Comparison Exhibit.

2. Escalation Rates

The Settling Parties agree with PG&E's proposed escalation rates and further agree that in this case no update of the escalation rates is required in this GRC.

3. Unbundled Cost Categories

The Settling Parties agree with PG&E's list of UCCs used to unbundle A&G expense and common plant and depreciation reserve.

4. Total Factor Productivity

The Settling Parties agree that PG&E has satisfactorily addressed the issue of Total Factor Productivity.

5. Proposed Rate Changes

The Settling Parties recommend the following changes to PG&E's unbundled or component electric distribution and electric Public Purpose Program (PPP) rates including the California Alternate Rates for Energy (CARE) surcharge:

5.1. The level of component electric distribution rates should be changed to reflect the revenue requirement in this proceeding.

5.2. The level of the electric CARE surcharge rate for test year 2003 should be changed to reflect the revised forecast of discounts CARE customers receive, which are embedded in PG&E's revenue at present rates estimate. No changes will be made in the system equal-cents-per-kWh revenue allocation and rate design methodology the Commission previously adopted for the CARE surcharge.

5.3. Two changes should be made to the electric Non-CARE PPP rates to reflect the revenue requirement adopted in Resolution E-3792, dated December 18, 2002, for PG&E's efficiency programs and to modify the currently adopted system average percent revenue allocation methodology for the energy efficiency programs revenue requirements, to reflect the cap on rates associated with these programs codified in Public Utilities Code (PUC) §399.8(c). PG&E will continue using a

schedule-level equal-cents- per-kWh rate design for the non-CARE portion of PPP rates.

5.4. PG&E will be allowed to include changes in the component electric PPP rates to reflect the revised revenue requirement in the annual advice filing required by Resolution E-3792. PG&E will also be permitted to change component PPP rates simultaneously with each adopted energy efficiency or CARE surcharge PPP revenue requirement revision. PG&E will develop the revised PPP rates using the most recently adopted revenue allocation and rate design methodologies.

(END OF ATTACHMENT A)

ATTACHMENT B

(ATTACHMENT B)

SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY, OFFICE OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, CITY AND COUNTY OF SAN FRANCISCO AND AGLET CONSUMER ALLIANCE

In accordance with Rule 51.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and Aglet Consumer Alliance (collectively, the "Parties") hereby enter into this Settlement Agreement in order to resolve disputed issues regarding the forecast test year 2003 electric generation revenue requirements and 2004, 2005 and, if applicable, 2006 attrition adjustments, to be authorized in PG&E's Application (A.) 02-11-017, the 2003 General Rate Case (GRC). The City and County of San Francisco (CCSF) joins in Section 16 of this Settlement Agreement, addressing the selective catalytic reduction (SCR) project at the Hunters Point Power Plant (Hunters Point). CCSF takes no position on any of the other issues resolved by this Settlement Agreement.

RECITALS

1. On November 8, 2002, PG&E filed its 2003 GRC application with the Commission. In that application, PG&E proposed an overall forecast test year 2003 electric generation revenue requirement of $1.02 billion. For 2004 and 2005, PG&E requested electric generation attrition adjustments based on PG&E's specific forecasts of necessary electric generation capital additions. For O&M expense, PG&E requested electric generation attrition adjustments in 2004 and 2005 based on 2003 O&M expense amounts.

2. On April 11, 2003 the ORA served, *inter alia*, its *Report on the Results for Utility Retained Generation for Pacific Gas and Electric Company* (ORA Report). ORA proposed an overall test year 2003 generation revenue requirement for PG&E's utility

retained generation of approximately $853 million.[1] This proposed 2003 electric generation revenue requirement reflected ORA's specific recommendations that the Commission:

- Reduce PG&E's request for rates to recover regulatory assets by $39.6 million by requiring PG&E to amortize the Financial Accounting Standard (FAS) 109 flow-through tax regulatory asset over 20 years, as opposed to PG&E's proposal to amortize this regulatory asset over 3 years;
- Reduce PG&E's depreciation expense for Diablo Canyon power plant (Diablo Canyon) by $ 13.7 million by requiring PG&E to depreciate the major assets at Diablo Canyon over 21 years, as opposed to PG&E's proposal of 15.8 years;
- Reduce PG&E's Diablo Canyon 2003 capital expenditures forecast by $4 million, to eliminate the Plant Information Management Systems project estimate for 2003;
- Reduce PG&E's forecast Diablo Canyon 2003 O&M expense by $11 million, by using a 3-year average of recorded Diablo Canyon O&M expense as a base, as opposed to PG&E's use of 2001 recorded as a base. ORA also proposed reducing the 2003 Diablo Canyon O&M expense forecast by an additional $2.3 million, reflecting its recommendation of a lower estimate for the reactor vessel chemical cleaning project;
- Reduce PG&E's request for rates to recover the return on fuel inventories by requiring PG&E to request recovery through the Energy Resources Recovery Account;

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[1] This amount reflects the dollars included in the detailed results of operations tables in ORA's Report. This amount is different than the amount reflected in the text of ORA's Report.

- Approve PG&E's electric generation attrition adjustment proposal, but not PG&E's forecast of 2004 and 2005 capital expenditures. Instead, ORA proposed that the Commission use PG&E's 2003 forecast of electric generation capital additions to calculate electric generation attrition adjustments for 2004 and 2005. For O&M expense, ORA supported PG&E's request that electric generation attrition adjustments in 2004 and 2005 be based on forecasts of 2004 and 2005 O&M expenses. ORA also proposed that the Commission defer PG&E's next GRC until 2007 and add an additional year of attrition in 2006.

3. On May 2, 2003, TURN and Aglet served intervenor testimony. TURN recommended that the Commission:

- Reduce PG&E's forecast 2003 O&M expense at the Humboldt Bay power plant by $1.4 million;
- Reduce PG&E's depreciation expense for Diablo Canyon by $13.7 million by requiring PG&E to depreciate the major assets at Diablo Canyon over 21 years, as opposed to PG&E's proposal of 15.8 years;
- Reduce PG&E's request for rates to recover regulatory assets by $81 million by requiring PG&E to amortize the FAS 109 flow-through tax regulatory asset over 20 years and the remaining generation-related regulatory assets over 10 years, as opposed to PG&E's proposal to amortize all of these regulatory assets over 3 years;
- Require a rate base offset of $26 million for the Post Retirement Benefits Other than Pensions (PBOPs) and Long Term Disability (LTD) funds collected in rates, but not deposited in the relevant trust funds;
- Require PG&E to record Diablo Canyon property taxes in a balancing account to be trued-up upon a Board of Equalization decision regarding the appropriate accounting for those taxes.

Aglet recommended that the Commission:

- Reject PG&E's proposed generation attrition methodology and adopt, instead, the attrition methodology Aglet proposed for PG&E's electric and gas distribution operations. Specifically, Aglet proposed that PG&E be granted no revenue requirement adjustment for electric generation costs in 2004, except for scheduled nuclear refueling expenses. For 2005, Aglet recommended a revenue requirement adjustment for electric generation costs reflecting the change in the Consumer Price Index (CPI), plus a Diablo Canyon refueling adjustment.
- Require PG&E to file separate applications supporting its requested rate recovery for Diablo Canyon refueling outage adjustments and the Low Pressure (LP) Turbine Rotor Replacement project at Diablo Canyon.

4. On May 22, 2003, PG&E served rebuttal testimony. In that rebuttal testimony PG&E presented, *inter alia*, forecast 2006 capital expenditures and O&M expenses, requesting that the Commission adopt these 2006 forecasts in the event the Commission adopted ORA's proposal for deferral of PG&E's next GRC until 2007 and the addition of another year of attrition in 2006.

5. Also on May 22, 2003, CCSF filed rebuttal testimony challenging PG&E's proposed recovery of the revenue requirement associated with a $500,000 capital expenditure in 2004 and a $15 million capital expenditure in 2005 for the SCR project at Hunters Point.

6. On or about June 13, 2003, the Parties held the first in a series of meetings to discuss a potential compromise of the generation issues in PG&E's 2003 GRC application. On July 1, 2003, the Parties reached agreement in principle, compromising on the generation issues in PG&E's 2003 GRC application as set forth in Sections 8-16 below.

7. Pursuant to Rule 51.1(b), on July 7, 2003, the Parties provided notice to all parties on the service list for A.02-11-017 that a settlement conference would occur on July 14, 2003. In addition to the Parties, representatives from CCSF and the Natural Resources Defense Council attended the July 14, 2003 settlement conference.

SETTLEMENT AGREEMENT

As a compromise among their respective litigation positions, and subject to the Recitals and Reservations set forth in this Settlement Agreement, the Parties hereby agree to fully resolve the generation revenue requirement issues in Exhibit (PG&E-10) of PG&E's 2003 GRC application, A.02-11-017, as follows:

8. **2003 Generation Revenue Requirement**

The Parties agree that a 2003 electric generation revenue requirement forecast of $955 million is reasonable. This amount reflects revisions from PG&E's original request as detailed in Section 11 below. This amount will change upon final execution of the Results of Operations model, due to the final establishment of the total revenue requirement for and the final allocation of administrative and general (A&G) expense and common plant, and due to the resolution of certain tax-related issues not specifically addressed or resolved in this Settlement Agreement, including those issues raised by recent revisions to the U.S. tax code.

9. **Attrition Proposal for 2004 and 2005**

PG&E shall be authorized annual electric generation attrition adjustments for 2004 and 2005 equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers; CPI change equals the latest Global Insight forecast prior to filing (for example October 2003, for year 2004) divided by the concurrent forecast for the current year (for example October 2003, for year 2003), minus one. The annual attrition increase for 2004 and 2005 will have a minimum of 1.5 percent and a maximum of 3.0 percent. PG&E shall file 2004 and 2005 attrition revenue requirements by advice letter due November 1 of the prior year. This settlement does not

address specific rate design of the 2004 and 2005 attrition revenue requirement adjustments.

Additional Attrition Items: In addition to the annual attrition adjustment as described above, the electric generation revenue requirement for 2004 and 2005 shall be adjusted to reflect the number of refueling outages at Diablo Canyon and additional security costs incurred at Diablo Canyon power plant as follows:

Refueling Outage Adjustment: The base revenue requirement for Diablo Canyon currently includes one refueling outage. If PG&E forecasts a second refueling outage in any one year, the authorized revenue requirement for 2003, 2004, 2005 and, if applicable, 2006, shall be increased to reflect a fixed revenue requirement of $32 million (in 2003 dollars) per refueling outage at Diablo Canyon power plant, adjusted only for CPI using the same formula described above for attrition year adjustments. The $32 million (in 2003 dollars) fixed revenue requirement per refueling outage reflects only the incremental operations and maintenance (O&M) forecast associated with refueling outage activities.

Additional Security Costs at Diablo Canyon Power Plant: For 2003, 2004, 2005 and, if applicable, 2006, PG&E shall be authorized a revenue requirement of $3 million (in 2003 dollars) per year, plus an attrition allowance using the same formula described above for attrition year adjustments.

10. **Attrition Proposal for 2006**

The parties reserve the right to oppose or support ORA's proposal for deferral of PG&E's next GRC until 2007 and the addition of an additional year of attrition in 2006. If the Commission does adopt ORA's proposal for deferral of PG&E's next GRC until 2007 and the addition of an additional year of attrition in 2006, PG&E shall be authorized a generation attrition adjustment equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers, subject to the same minimum of 1.5% and maximum of 3% as is applicable to the generation attrition adjustments for 2004 and 2005, plus an additional 1%. For example, under this

methodology, if the forecast change in CPI is 1% for 2006, the generation attrition adjustment would be calculated by multiplying the previous year authorized revenue requirement by 2.5% (the 1.5% minimum plus 1%). If the forecast change in CPI is 5% for 2006, the generation attrition adjustment would be calculated by multiplying the previous year authorized revenue requirement by 4% (the 3% maximum plus 1%). The CPI change equals the latest Global Insight forecast prior to filing (for example October 2005, for year 2006) divided by the concurrent forecast for the current year (for example October 2005, for year 2005), minus one.

The 2006 generation attrition adjustment shall also be adjusted to reflect forecasted refueling outages at Diablo Canyon and additional security costs incurred at Diablo Canyon power plant, as described in Section 9. PG&E shall file the 2006 generation attrition revenue requirement by advice letter due November 1 of the prior year. This settlement does not address specific rate design of the 2006 attrition revenue requirement adjustments.

If the Commission does not adopt ORA's proposal for deferral of PG&E's next GRC until 2007, this Section 10 will be moot. All other sections of this settlement will remain enforceable, if approved by the Commission in a final decision in PG&E's 2003 GRC.

11. Specific Description Of Revisions To Forecast 2003 Generation Revenue Requirement

Amortization of Generation Regulatory Assets: The generation regulatory assets should be amortized over the remainder of the 10-year schedule the Commission adopted in Decision 02-04-016 (i.e., 9 year amortization starting in 2003). The amortization covers the following generation regulatory assets: WAPA, Helms, Loss on Sale of Power Plants.

Amortization of the FAS 109 Regulatory Asset : The FAS 109 tax flow-through regulatory asset should be amortized over the remainder of the 10-year schedule the Commission adopted in Decision 02-04-016 (i.e., 9 year amortization starting in 2003).

Return on Regulatory Assets/TURN Rate Base Offset: The rate of return earned on the WAPA, Helms and Loss on Sale of Power Plants regulatory assets will be removed from PG&E's revenue requirement, without prejudice. The issue as to whether a return on such regulatory assets is appropriate will be addressed in the end-of-freeze phase of the Rate Stabilization Proceeding, A.00-11-056. TURN's proposal for a $26 million rate base offset in connection with recovery of the post-retirement benefits other than pensions (PBOPs) and long-term disability regulatory assets will not be reflected in the generation revenue requirement and this issue will similarly be addressed in the end-of-freeze phase of the Rate Stabilization Proceeding.

Diablo Canyon Depreciation Proposal: Parties agree that it is appropriate to depreciate the major components of Diablo Canyon power plant over 19 years beginning in 2003. Parties further agree that it is appropriate to depreciate utility common plant items at Diablo Canyon, e.g., fleet vehicles and computers, in accordance with the depreciation schedule adopted for such assets in the 2003 GRC decision.

Additional Security Costs at Diablo Canyon Power Plant: For 2003, PG&E shall be authorized $3 million (in 2003 dollars) in revenue requirements for additional security costs at Diablo Canyon power plant needed to comply with Nuclear Regulatory Commission orders issued April 29, 2003.

12. **Steam Generator Replacement Project at Diablo Canyon Power Plant**

PG&E's 2003 GRC application does not request any specific relief in connection with the steam generator replacement project PG&E has planned at Diablo Canyon. In advance of its next GRC, PG&E agrees to file a separate ratemaking application requesting Commission approval of the steam generator replacement project at Diablo Canyon.

13. **Low Pressure Turbine Rotor Replacement Project at Diablo Canyon Power Plant**

Parties agree that the LP Turbine Rotor Replacement project at Diablo Canyon power plant may be reviewed in PG&E's next general rate case.

14. **Diablo Canyon Property Taxes**

Given the uncertainty of State Board of Equalization Action, PG&E will retain current balancing account treatment of Diablo Canyon property taxes to ensure PG&E recovers the actual amount of property taxes paid in 2003, 2004, 2005 and, if applicable, 2006.

15. **Finality of 2002 Utility Retained Generation Revenue Requirement**

Based upon their review of PG&E's 2002 utility retained generation expenditures submitted in conjunction with PG&E's application, the Parties agree that it is unnecessary to conduct a further review of recorded 2002 URG capital expenditures, satisfying the reasonableness review requirement set forth in Ordering Paragraph 5 of Decision 02-04-016. Parties further agree that PG&E's compliance filing for Advice Letter 2240-E-A constitutes the true-up of capital costs to actual costs that are the subject of Ordering Paragraph 5 of Decision 02-04-016. PG&E agrees that ORA may conduct an audit of 2002 URG operating expenses as part of its review of PG&E's compliance filing for Advice Letter 2240-E-A.

16. **Hunters Point Selective Catalytic Reduction Project**

PG&E and the City and County of San Francisco agreed in a settlement approved by the Commission in Decision 98-10-029 to shut down the Hunters Point Power Plant as soon as the plant is no longer needed for reliability in San Francisco and northern San Mateo County. As a result, PG&E does not intend to or desire to proceed with the SCR Project at Hunters Point. Under this 2003 GRC settlement, PG&E has removed its 2004 forecast of $500,000 and its 2005 forecast of $15 million for installation of SCR pollution control equipment at Hunters Point power plant. The resulting test year 2003 revenue

requirement agreed upon in this settlement does not reimburse PG&E for the costs of the SCR project. To the extent that the California Independent System Operator does not authorize PG&E to close down the Hunters Point Power Plant on a timely basis, PG&E shall use all interchangeable emission reduction credits it is legally entitled to use, consistent with the *Settlement Agreement Regarding the Banking and Usage of IERCs in an Effort to Expedite Closure of Hunters Point Power Plant*, dated October 22, 2002, and other available interim measures, to ensure reliability and comply with applicable air quality requirements. In the event that these interim measures are inadequate, PG&E may be required to proceed with the SCR project in order to ensure electric reliability. In such an event, PG&E may file a separate application with the Commission seeking rate recovery of the costs of the SCR project.

RESERVATIONS

17. The Parties agree that this Settlement Agreement represents a compromise, not agreement or endorsement of disputed facts and law presented by the Parties in the 2003 GRC.

18. The Parties shall jointly request Commission approval of this Settlement Agreement. The Parties additionally agree to actively support prompt approval of the Settlement Agreement. Active support shall include briefing, comments on the proposed decision, written and oral testimony if testimony is required, appearances, and other means as needed to obtain the approvals sought. The Parties further agree to participate jointly in briefings to Commissioners and their advisors as needed regarding the Settlement Agreement and the issues compromised and resolved by it.

19. This Settlement Agreement embodies the entire understanding and agreement of the Parties with respect to the matters described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations or understandings among the Parties.

20. The Settlement Agreement may be amended or changed only by a written agreement signed by the Parties.

21. The Parties have bargained earnestly and in good faith to achieve this Settlement Agreement. The Parties intend the Settlement Agreement to be interpreted and treated as a unified, interrelated agreement. The Parties therefore agree that if the Commission fails to approve the Settlement Agreement as reasonable, and adopt it unconditionally and without modification, including the findings and determinations requested herein, any Party may in its sole discretion, elect to terminate the Settlement Agreement. The Parties further agree that any material change to the Settlement Agreement shall give each Party in its sole discretion, the option to terminate the Settlement Agreement. In the event the Settlement is terminated, the Parties will request that the unresolved issues in Application 02-11-017 be heard and briefed at the earliest convenient time.

22. This Settlement Agreement represents a compromise of respective litigation positions and is not intended to establish binding precedent for any future proceeding. The Parties have assented to the terms of this Settlement Agreement only for the purpose of arriving at the compromise embodied herein.

23. Each of the Parties hereto and their respective counsel and advocates have contributed to the preparation of this Settlement Agreement. Accordingly, the Parties agree that no provision of this Settlement Agreement shall be construed against any Party because that Party or its counsel drafted the provision.

24. This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

25. This Settlement Agreement shall become effective among the Parties on the date the last Party executes the Settlement as indicated below.

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

PACIFIC GAS AND ELECTRIC COMPANY

By: _____

Name: _____

Date: _____

THE OFFICE OF RATEPAYER ADVOCATES

By: _____

Name: _____

Date: _____

THE UTILITY REFORM NETWORK

By: _____

Name: _____

Date: _____

AGLET CONSUMER ALLIANCE

By: _____

Name: _____

Date: _____

THE CITY AND COUNTY OF SAN FRANCISCO

By: _____

Name: _____

Date: _____

(END OF ATTACHMENT B)

ATTACHMENT C

(ATTACHMENT C)

STIPULATION AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY, SAN LUIS OBISPO MOTHERS FOR PEACE, DIABLO CANYON INDEPENDENT SAFETY COMMITTEE, OFFICE OF RATEPAYER ADVOCATES CALIFORNIA ENERGY COMMISSION, AND THE UTILITY REFORM NETWORK

April 23, 2003

In accordance with Rule 51.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), San Luis Obispo Mothers for Peace (M4P), Diablo Canyon Independent Safety Committee (DCISC), California Energy Commission (CEC), the Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN) (collectively, the "Parties") hereby enter into this Stipulation in order to resolve the disputed issues regarding the continued existence and membership of the Diablo Canyon Independent Safety Committee presented in PG&E's Application (A.) 02-11-017, the 2003 General Rate Case (GRC).

RECITALS

1. On November 8, 2002, PG&E filed its 2003 GRC application with the Commission. In that application, PG&E proposed to eliminate the DCISC.

2. The DCISC has objected to PG&E's proposal to eliminate the DCISC. On December 13, 2002, the DCISC filed a Response and on January 24, 2003, it filed a prehearing conference statement, opposing PG&E's proposal to eliminate the DCISC and seeking to strike the proposal from consideration in PG&E's 2003 GRC.

3. On January 23, 2003, the CEC filed a prehearing conference statement, both opposing elimination of the DCISC and raising for consideration in PG&E's 2003

GRC the advisability of a separate proceeding or separate phase to consider questions involving the DCISC. The CEC also endorsed a proposal by the M4P to revise the nomination and appointment provisions originally adopted by the Commission when it approved the Diablo Canyon settlement, D.88-12-083. The M4P proposal had originally been advanced by the M4P in a Petition to Modify D.88-12-083 filed on November 29, 2001.

4. In a Notice of Intent to Claim Compensation filed February 25, 2003, the M4P stated its intention to participate in PG&E's 2003 GRC proceeding on the issue of eliminating the DCISC. On March 12, 2003, the M4P filed a petition to transfer its petition to modify D.88-12-083 from the Rate Stabilization Proceeding docket, A.00-11-056, to the 2003 GRC docket, A.02-11-017.

5. The ORA did not specifically address this issue through its Protest or Prehearing Conference Statement. At the meet and confer session referred to in Paragraph 9 below, ORA stated its support for continuation of the DCISC.

6. At the January 28, 2003 prehearing conference, PG&E and the DCISC proposed that interested parties participate in a meet and confer session to determine the process by which the DCISC issues should be addressed in PG&E's 2003 GRC.

7. The Commission approved of this approach in the *Assigned Commissioner's Ruling Establishing Scope, Schedule and Procedures for Proceeding* dated February 13, 2003, stating:

> On March 12, 2003, PG&E will host a meet and confer to develop procedural recommendations regarding how issues surrounding the Diablo Canyon Independent Safety Committee should be handled. The procedural recommendation should address the need for testimony on this subject, whether the pending petition to modify by Mothers for Peace in A.00-11-038 et al. should

be addressed in these proceedings, the possibility for settlement or stipulation, and propose a schedule. Once the recommendation is received, the ALJ and I will rule on how to proceed on this issue.

8. On February 7, 2003, PG&E sent an email to all individuals on the service list for PG&E's 2003 GRC, A.02-11-017, informing them PG&E would host a meet and confer session on March 12, 2003, at PG&E's headquarters at 77 Beale Street, San Francisco, CA 94105. Additionally, PG&E provided all parties information regarding how to participate by telephone.

9. On March 12, 2003, PG&E hosted the meet and confer session. Participants included: PG&E, the DCISC, the M4P, the CEC, and the ORA. TURN was not present, but the M4P representative indicated that she had been authorized to speak on TURN's behalf.

10. TURN agreed to the terms of this stipulation on April 4, 2003.

11. Pursuant to Rule 51 of the Commission's Rules of Practice and Procedure, on April 11, 2003, PG&E held a conference to discuss the terms of this Stipulation. All parties to the service list for A.02-11-017 received notice of the conference seven days in advance.

STIPULATION

As a compromise among their respective litigation positions, and subject to the Recitals and Reservations set forth in this Stipulation Agreement, the Parties hereby stipulate as follows:

12. The M4P petition to modify Decision 88-12-083 ("M4P Petition"), and all documents filed in response thereto, should be transferred from A.00-11-038 et al., to the

docket for PG&E's 2003 GRC, A.02-11-017 and should be addressed in the 2003 GRC decision. The Parties further agree on a supplemental briefing schedule on the M4P Petition. Under the proposed supplemental briefing schedule, M4P will update the M4P Petition through submission of a supplemental brief on May 23, 2003. Interested parties may file reply briefs responding to the M4P supplemental brief on June 20, 2003. The Parties reserve their rights to fully support or oppose the M4P petition and to seek appropriate relief at the Commission or elsewhere to the extent the Commission grants relief that is unacceptable to a Party.

13. PG&E hereby withdraws from the 2003 GRC Application its proposal to terminate the DCISC. As a result, with the approval of the Commission as part of its final decision on PG&E's 2003 GRC Application, the DCISC will continue to be funded through cost-of-service rates through the next rate case cycle, at the funding level established by the Commission in D.97-05-088 of $673,077, plus 1.5% annual escalation. The 2003 funding, based on the 1.5% escalation rate, is $747,011. To the extent that the Commission grants the M4P Petition, in whole or in part, and this results in an increase in costs associated with the DCISC beyond such authorized funding levels, the Parties hereby agree to support recovery in rates of any such increased costs either through an attrition mechanism adjustment or submission of a supplemental application. The issue of whether the DCISC will continue to be funded in the base generation revenue requirement established in the GRC beyond the 2003 rate case cycle will not be addressed until PG&E's next GRC.

14. As the parties have resolved the funding issues associated with the DCISC in this stipulation and have agreed upon a supplemental briefing process to update the

M4P Petition to Modify Decision 88-12-083, it is not necessary to hold evidentiary hearings. The Parties agree to support the M4P's interest in scheduling a public participation hearing in the City of San Luis Obispo to provide an opportunity for the community to address the M4P Petition or other issues of local concern pertaining to PG&E's 2003 GRC.

15. The nominating and appointment procedures for the DCISC adopted by the Commission in Decision 88-12-083 and sustained by Commission order in D.97-05-088 shall continue to be implemented. In the event the Commission issues a final decision in PG&E's 2003 GRC approving the changes sought by the M4P petition, those procedures may be modified prospectively. The Parties agree that it is important to maintain the continuity and expertise of membership provided by the staggered term membership requirements in the nominating and appointment procedures adopted by the Commission in Decision 88-12-083. Therefore, the Parties agree to support continuation of the staggered term requirement.

RESERVATIONS

16. The Parties agree that this Stipulation represents a compromise, not agreement or endorsement of disputed facts and law presented by the Parties in the 2003 GRC.

17. The Parties shall jointly request Commission approval of this Stipulation. The Parties additionally agree to actively support prompt approval of the Stipulation. Active support shall include briefing, comments on the proposed decision, written and oral testimony if testimony is required, appearances, and other means as needed to obtain the approvals sought. The Parties further agree to participate jointly in briefings to

Commissioners and their advisors as needed regarding the Stipulation and the issues compromised and resolved by it. The Parties reserve their rights to advocate individual positions with respect to the issues presented by M4P in its Petition and any subsequent modifications thereto.

18. This Stipulation embodies the entire understanding and agreement of the Parties with respect to the matters described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations or understandings between the Parties.

19. The Stipulation may be amended or changed only by a written agreement signed by the Parties.

20. The Parties have bargained earnestly and in good faith to achieve this Stipulation. The Parties intend the Stipulation to be interpreted and treated as a unified, interrelated agreement. The Parties therefore agree that if the Commission fails to approve the Stipulation as reasonable, and adopt it unconditionally and without modification, including the findings and determinations requested herein, any Party may in its sole discretion, elect to terminate the Stipulation. The Parties further agree that any material change to the Stipulation shall give each Party in its sole discretion, the option to terminate the Stipulation. The Parties further agree that if the Commission does not approve the Stipulation, the DCISC, CEC, M4P, ORA and TURN reserve the right to seek admission of testimony relating to the proposal of PG&E in its 2003 GRC application to eliminate the DCISC.

21. This Stipulation represents a compromise of respective litigation positions and is not intended to establish binding precedent for any future proceeding. The Parties

have assented to the terms of this Stipulation Agreement only for the purpose of arriving at the compromise embodied herein.

22. Each of the Parties hereto and their respective counsel and advocates have contributed to the preparation of this Stipulation. Accordingly, the Parties agree that no provision of this Stipulation shall be construed against any Party because that Party or its counsel drafted the provision.

23. This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

24. This Stipulation shall become effective among the Parties on the date the last Party executes the Stipulation as indicated below.

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

PACIFIC GAS AND ELECTRIC COMPANY

By: _____

Name: _____

Date: _____

MOTHERS FOR PEACE

By: _____

Name: _____

Date: _____

DIABLO CANYON INDEPENDENT SAFETY COMMITTEE

By: _____

Name: _____

Date: _____

CALIFORNIA ENERGY COMMISSION

By: _____

Name: _____

Date: _____

THE OFFICE OF RATEPAYER ADVOCATES

By: _____

Name: _____

Date: _____

THE UTILITY REFORM NETWORK

By: _____

Name: _____

Date: _____

(END OF ATTACHMENT C)

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ATTACHMENT D

Attachment D

Attachment D1	Results of Operations for Test Year 2003 – Electric Distribution
Attachment D2	Results of Operations for Test Year 2003 – Gas Distribution
Attachment D3	Results of Operations for Test Year 2003 – Electric Generation
Attachment D4	Attrition Results – Years 2004 through 2006
Attachment D5	Allocations of Administrative and General Expense and Common Plant
Attachment D6	Depreciation Parameters

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Revenue Summary - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUES AT PRESENT RATES		
	CPUC Revenues (Retail)		
1	Revenues from Sales	2,239,718	1
2	Plus: Approved Other Operating Revenue	22,281	2
3	CPUC Revenue	2,261,999	3
4	Less: Non-Applicable Revenue	15,444	4
5	Rate Case Revenue	2,246,555	5
	FERC Revenues (Wholesale)		
6	Revenues from Sales	0	6
7	Plus: Other Operating Revenue	10,789	7
8	FERC Revenue	10,789	8
9	Less: Non-Applicable Revenue	0	9
10	Rate Case Revenue	10,789	10
11	Total Rate Case Revenue	2,257,344	11
	INCREASE IN RATE CASE REVENUE		
12	CPUC Jurisdiction	234,579	12
13	FERC Jurisdiction	1,110	13
14	Total Increase	235,690	14
15	Percent	10.44%	15
	INCREASE IN CPUC REVENUE FROM SALES		
16	Amount	189,560	16
17	Percent	8.46%	17
	REVENUES AT PROPOSED RATES		
	CPUC Revenues (Retail)		
18	Revenues from Sales	2,429,278	18
19	Plus: Other Operating Revenue	67,300	19
20	CPUC Revenue	2,496,578	20
21	Less: Non-Applicable Revenue	15,444	21
22	Rate Case Revenue	2,481,134	22
	FERC Revenues (Wholesale)		
23	Revenues from Sales	1,110	23
24	Plus: Other Operating Revenue	10,789	24
25	FERC Revenue	11,899	25
26	Less: Non-Applicable Revenue	(0)	26
27	Rate Case Revenue	11,899	27
28	Total Rate Case Revenue	2,493,034	28

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Results of Operations - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUE		
1	Revenue at Effective Rates	2,508,478	1
2	Less Non-General Revenue	15,444	2
3	General Rate Case Revenue	2,493,034	3
	OPERATING EXPENSES		
4	*Energy Costs	0	4
5	*Other Production	16,600	5
6	*Storage	0	6
7	*Transmission	552	7
8	*Distribution	391,500	8
9	*Customer Accounts	199,900	9
10	Uncollectibles	4,979	10
11	*Customer Services	1,364	11
12	*Administrative and General	208,838	12
13	Franchise Requirements	18,733	13
14	Amortization	0	14
15	Wage Change Impacts	37,373	15
16	Other Price Change Impacts	22,750	16
17	*Other Adjustments	(3,795)	17
18	Subtotal Expenses	898,794	18
	TAXES		
19	Superfund	0	19
20	Property	85,545	20
21	Payroll	30,604	21
22	Business	311	22
23	Other	185	23
24	State Corporation Franchise	51,677	24
25	Federal Income	255,809	25
26	Total Taxes	424,131	26
27	Depreciation	460,339	27
28	Fossil Decommissioning	0	28
29	Nuclear Decommissioning	0	29
30	Total Operating Expenses	1,783,264	30
31	Net for Return	709,770	31
32	Rate Base	7,685,463	32
	RATE OF RETURN		
33	On Rate Base	9.24%	33
34	On Equity	11.22%	34

* = Constant 2000 Dollars

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Income Tax Summary - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenues	2,493,034	1
2	O&M Expenses	898,794	2
3	Nuclear Decommissioning Expense	0	3
4	Superfund Tax	0	4
5	Taxes Other Than Income	116,645	5
6	Subtotal	1,477,595	6
	DEDUCTIONS FROM TAXABLE INCOME		
7	Interest Charges	268,893	7
8	Fiscal/Calendar Adjustment	1,233	8
9	Operating Expense Adjustments	(17,826)	9
10	Capitalized Interest Adjustment	0	10
11	Capitalized Inventory Adjustment	0	11
12	Vacation Accrual Reduction	(1,317)	12
13	Capitalized Other	4,958	13
14	Subtotal Deductions	255,942	14
	CCFT TAXES		
15	State Operating Expense Adjustment	3,907	15
16	State Tax Depreciation - Declining Balance	4	16
17	State Tax Depreciation - Fixed Assets	536,194	17
18	State Tax Depreciation - Other	0	18
19	Removal Costs	29,222	19
20	Repair Allowance	66,946	20
21	Subtotal Deductions	892,214	21
22	Taxable Income for CCFT	585,381	22
23	CCFT	51,748	23
24	State Tax Adjustment	4	24
25	Current CCFT	51,752	25
26	Defense Facilities Credit	(0)	26
27	Deferred Taxes - Interest	43	27
28	Deferred Taxes - Vacation	(117)	28
29	Deferred Taxes - Other	0	29
30	Deferred Taxes - Fixed Assets	0	30
31	Total CCFT	51,677	31
	FEDERAL TAXES		
32	CCFT - Prior Year	32,392	32
33	Federal Operating Expense Adjustment	6,201	33
34	Federal Tax Depreciation - Declining Balar	4	34
35	Federal Tax Depreciation - SLRL	0	35
36	Federal Tax Depreciation - Fixed Assets	643,107	36
37	Federal Tax Depreciation - Other	0	37
38	Removal Costs	3,270	38
39	Repair Allowance	50,820	39
40	Preferred Dividend Credit	334	40
41	Subtotal Deductions	992,070	41
42	Taxable Income for FIT	485,525	42
43	Federal Income Tax	169,934	43
44	Defense Facilities Credit	(0)	44
45	Flowback of Excess Deferred Taxes	4	45
46	Deferred Taxes - Interest	971	46
47	Deferred Taxes - Vacation	(420)	47
48	Deferred Taxes - Other	0	48
49	Deferred Taxes - Fixed Assets	85,320	49
50	Total Federal Income Tax	255,809	50

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Expense Summary - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Expenses in 2000 Dollars		
1	Production (Generation)		1
2	Labor	12,603	2
3	Materials and Services	3,997	3
4	Other	0	4
5	Total	16,600	5
6	Transmission		6
7	Labor	276	7
8	Materials and Services	276	8
9	Other	0	9
10	Total	552	10
11	Distribution		11
12	Labor	176,379	12
13	Materials and Services	215,122	13
14	Other	0	14
15	Total	391,500	15
16	Customer Accounts		16
17	Labor	126,527	17
18	Materials and Services	59,401	18
19	Other	13,972	19
20	Total	199,900	20
21	Customer Service		21
22	Labor	520	22
23	Materials and Services	844	23
24	Other	0	24
25	Total	1,364	25
26	Administrative and General		26
27	Labor	44,100	27
28	Materials and Services	44,424	28
29	Other	79,766	29
30	Wage Related	11,129	30
31	Medical	29,419	31
32	Total	208,838	32
33	**Total Expenses in 2000 Dollars**		33
34	**Labor**	360,405	34
35	**Materials and Services**	324,063	35
36	**Other**	93,738	36
37	**Wage Related**	11,129	37
38	**Medical**	29,419	38
39	**Total**	818,754	39
40	**Total Expenses in 2003 Dollars**		40
41	**Labor**	396,658	41
42	**Materials and Services**	338,244	42
43	**Other**	93,738	43
44	**Wage Related**	12,248	44
45	**Medical**	34,193	45
46	**Total**	875,082	46

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Franchise Fees and Uncollectible Accounts Expenses - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenue		1
2	Rate Case Revenues	2,493,034	2
3	Percent Of Revenue From Customers	99.8510%	3
4	Rate Case Revenues From Customers	2,489,325	4
5	Uncollectible Accounts		5
6	Uncollectible Rate	0.002000	6
7	Uncollectible Accounts Expense	4,979	7
8	Franchise Fees		8
9	Rate Case Revenues From Customers	2,489,325	9
10	Uncollectible Accounts Expense	4,979	10
11	Net Rate Case Revenue From Customers	2,484,346	11
12	Franchise Rate	0.007541	12
13	Franchise Fees Expense	18,733	13

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Taxes Other than Income - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Property (Ad Valorem) Tax	85,545	1
2	Federal Insurance Contribution Act	26,876	2
3	Federal Unemployment Insurance	387	3
4	State Unemployment Insurance	1,016	4
5	San Francisco Payroll Tax	2,326	5
6	Total Payroll Taxes	30,604	6
7	Other Taxes	496	7
8	Total Taxes Other Than Income	116,645	8

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Plant In Service - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	2000 End-of-Year Plant		1
2	Functional	11,732,114	2
3	Common, General, and Intangible	1,344,906	3
4	Total 2000 End-of-Year Plant	13,077,021	4
5	2001 Full-Year Net Additions		5
6	Functional	529,427	6
7	Common, General, and Intangible	35,110	7
8	Total 2001 Net Additions	564,537	8
9	2001 End-of-Year Plant		9
10	Functional	12,261,541	10
11	Common, General, and Intangible	1,380,016	11
12	Total 2001 End-of-Year Plant	13,641,558	12
13	2002 Full-Year Net Additions		13
14	Functional	495,058	14
15	Common, General, and Intangible	42,373	15
16	Total 2002 Net Additions	537,432	16
17	2002 End-of-Year Plant		17
18	Functional	12,756,600	18
19	Common, General, and Intangible	1,422,390	19
20	Total 2002 End-of-Year Plant	14,178,989	20
21	2003 Full-Year Net Additions		21
22	Functional	547,695	22
23	Common, General, and Intangible	66,521	23
24	Total 2003 Net Additions	614,216	24
25	2003 End-of-Year Plant		25
26	Functional	13,304,294	26
27	Common, General, and Intangible	1,488,911	27
28	Total 2003 End-of-Year Plant	14,793,205	28
29	**2003 Weighted Average Net Additions**		29
30	Functional	274,523	30
31	Common, General, and Intangible	17,465	31
32	Total 2003 Weighted Average Net Additions	291,989	32
33	**2003 Weighted Average Plant**		33
34	Functional	13,031,123	34
35	Common, General, and Intangible	1,439,855	35
36	Total 2003 Weighted Average Plant	14,470,978	36

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Depreciation - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Depreciation		
1	Production	468	1
2	Transmission	507	2
3	Distribution	385,823	3
4	General	4,957	4
5	Subtotal	391,754	5
6	Common Utility Allocation	68,585	6
7	Total	460,339	7
8	**Depreciation Reserve**		8
9	Production	6,821	9
10	Transmission	9,199	10
11	Distribution	5,469,377	11
12	General	51,258	12
13	Subtotal	5,536,655	13
14	Common Utility Allocation	526,033	14
15	Total	6,062,688	15
	Weighted Average Depreciation Reserve		
16	Production	6,145	16
17	Transmission	9,157	17
18	Distribution	5,316,190	18
19	General	50,303	19
20	Subtotal	5,381,794	20
21	Common Utility Allocation	520,160	21
22	Total	5,901,954	22

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied By Investors - Test Year
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Operational Cash Requirements		
1	Required Bank Balances	0	1
2	Special Deposits and Working Funds	181	2
3	Other Receivables	25,118	3
4	Prepayments	3,180	4
5	Deferred Debits, Company-Wide	(312)	5
	Less		
6	Working Cash Capital not Supplied by Investors	4,071	6
7	Goods Delivered to Construction Sites	2,236	7
8	Accrued Vacation	0	8
	Add		
9	Prepayment, Departmental	(63,000)	9
10	Total Operational Cash Requirement	(41,140)	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	50,766	11
12	Working Cash Capital Supplied by Investors	9,626	12

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Rate Base - Test Year 2003
Electric Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	WEIGHTED AVERAGE PLANT		
1	Plant	14,470,978	1
2	Plant Held for Future Use	0	2
3	Common Plant - Allocation	0	3
4	Common Plant Held for Future Use	0	4
5	Total Weighted Average Plant	14,470,978	5
	WORKING CAPITAL		
6	Material and Supplies - Fuel	0	6
7	Material and Supplies - Other	20,398	7
8	Working Cash	9,626	8
9	Total Working Capital	30,024	9
	ADJUSTMENTS FOR TAX REFORM ACT		
10	Deferred Capitalized Interest	7,921	10
11	Deferred Vacation	16,829	11
12	Deferred CIAC Tax Effects	173,175	12
13	Total Adjustments	197,925	13
	LESS DEDUCTIONS		
14	Customer Advances	78,308	14
15	Accumulated Deferred Taxes - Defense	0	15
16	Accumulated Deferred Taxes - Fixed Assets	963,435	16
17	Accumulated Deferred Taxes - Other	0	17
18	Deferred ITC	69,767	18
19	Deferred Tax - Other	0	19
20	Total Deductions	1,111,510	20
21	DEPRECIATION RESERVE	5,901,954	21
22	TOTAL RATE BASE	7,685,463	22

Attachment D1
Pacific Gas and Electric Company
2003 General Rate Case
Net To Gross Multiplier - Test Year 2003
Electric Distribution

Line No.	Description	Adopted	Line No.
1	Revenue Base	1.000000	1
2	Less Interdepartmental Revenue	0.001490	2
3	Percent Revenue From Jurisdictional Customers	0.998510	3
4	Uncollectibles Percentage	0.001997	4
5	Franchise Requirements	0.007514	5
6	Total Uncollectibles and Franchise Requirements	0.009511	6
7	Net For State Income Taxes	0.990489	7
8	State Income Tax Percentage	0.088400	8
9	State Income Taxes	0.087559	9
10	Net For Federal Income Taxes	0.990489	10
11	Federal Income Tax Percentage	0.350000	11
12	Federal Income Taxes	0.346671	12
13	Net Operating Revenue	0.556258	13
14	Net To Gross Multiplier	1.797725	14

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Revenue Summary - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUES AT PRESENT RATES		
	CPUC Revenues (Retail)		
1	Revenues from Sales	894,411	1
2	Plus: Approved Other Operating Revenue	5,858	2
3	CPUC Revenue	900,269	3
4	Less: Non-Applicable Revenue	25,374	4
5	Rate Case Revenue	874,895	5
	FERC Revenues (Wholesale)		
6	Revenues from Sales	0	6
7	Plus: Other Operating Revenue	0	7
8	FERC Revenue	0	8
9	Less: Non-Applicable Revenue	0	9
10	Rate Case Revenue	0	10
11	Total Rate Case Revenue	874,895	11
	INCREASE IN RATE CASE REVENUE		
12	CPUC Jurisdiction	51,618	12
13	FERC Jurisdiction	0	13
14	Total Increase	51,618	14
15	Percent	5.90%	15
	INCREASE IN CPUC REVENUE FROM SALES		
16	Amount	41,176	16
17	Percent	4.60%	17
	REVENUES AT PROPOSED RATES		
	CPUC Revenues (Retail)		
18	Revenues from Sales	935,587	18
19	Plus: Other Operating Revenue	16,300	19
20	CPUC Revenue	951,887	20
21	Less: Non-Applicable Revenue	25,374	21
22	Rate Case Revenue	926,513	22
	FERC Revenues (Wholesale)		
23	Revenues from Sales	0	23
24	Plus: Other Operating Revenue	0	24
25	FERC Revenue	0	25
26	Less: Non-Applicable Revenue	0	26
27	Rate Case Revenue	0	27
28	Total Rate Case Revenue	926,513	28

Attachment D2
Pacific Gas and Gas Company
2003 General Rate Case
Results of Operations - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUE		
1	Revenue at Effective Rates	951,887	1
2	Less Non-General Revenue	25,374	2
3	General Rate Case Revenue	926,513	3
	OPERATING EXPENSES		
4	*Energy Costs	0	4
5	*Other Production	0	5
6	*Storage	0	6
7	*Transmission	3,356	7
8	*Distribution	118,500	8
9	*Customer Accounts	154,700	9
10	Uncollectibles	1,853	10
11	*Customer Services	3,482	11
12	*Administrative and General	118,109	12
13	Franchise Requirements	8,942	13
14	Amortization	0	14
15	Wage Change Impacts	21,102	15
16	Other Price Change Impacts	13,351	16
17	*Other Adjustments	(3,100)	17
18	Subtotal Expenses	440,296	18
	TAXES		
19	Superfund	0	19
20	Property	21,100	20
21	Payroll	17,272	21
22	Business	175	22
23	Other	105	23
24	State Corporation Franchise	15,001	24
25	Federal Income	65,429	25
26	Total Taxes	119,081	26
27	Depreciation	175,228	27
28	Fossil Decommissioning	0	28
29	Nuclear Decommissioning	0	29
30	Total Operating Expenses	734,605	30
31	Net for Return	191,908	31
32	Rate Base	2,077,996	32
	RATE OF RETURN		
33	On Rate Base	9.24%	33
34	On Equity	11.22%	34

* = Constant 2000 Dollars

Attachment D2
Pacific Gas and Gas Company
2003 General Rate Case
Income Tax Summary - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenues	926,513	1
2	O&M Expenses	440,296	2
3	Nuclear Decommissioning Expense	0	3
4	Superfund Tax	0	4
5	Taxes Other Than Income	38,652	5
6	Subtotal	447,565	6
	DEDUCTIONS FROM TAXABLE INCOME		
7	Interest Charges	72,703	7
8	Fiscal/Calendar Adjustment	450	8
9	Operating Expense Adjustments	(12,026)	9
10	Capitalized Interest Adjustment	0	10
11	Capitalized Inventory Adjustment	0	11
12	Vacation Accrual Reduction	(809)	12
13	Capitalized Other	3,960	13
14	Subtotal Deductions	64,278	14
	CCFT TAXES		
15	State Operating Expense Adjustment	1,194	15
16	State Tax Depreciation - Declining Balance	0	16
17	State Tax Depreciation - Fixed Assets	204,696	17
18	State Tax Depreciation - Other	0	18
19	Removal Costs	6,940	19
20	Repair Allowance	0	20
21	Subtotal Deductions	277,109	21
22	Taxable Income for CCFT	170,457	22
23	CCFT	15,068	23
24	State Tax Adjustment	0	24
25	Current CCFT	15,068	25
26	Defense Facilities Credit	0	26
27	Deferred Taxes - Interest	4	27
28	Deferred Taxes - Vacation	(72)	28
29	Deferred Taxes - Other	0	29
30	Deferred Taxes - Fixed Assets	0	30
31	Total CCFT	15,001	31
	FEDERAL TAXES		
32	CCFT - Prior Year	7,767	32
33	Federal Operating Expense Adjustment	1,998	33
34	Federal Tax Depreciation - Declining Balance	0	34
35	Federal Tax Depreciation - SLRL	0	35
36	Federal Tax Depreciation - Fixed Assets	262,526	36
37	Federal Tax Depreciation - Other	0	37
38	Removal Costs	777	38
39	Repair Allowance	0	39
40	Preferred Dividend Credit	43	40
41	Subtotal Deductions	337,390	41
42	Taxable Income for FIT	110,176	42
43	Federal Income Tax	38,561	43
44	Defense Facilities Credit	0	44
45	Flowback of Excess Deferred Taxes	0	45
46	Deferred Taxes - Interest	304	46
47	Deferred Taxes - Vacation	(258)	47
48	Deferred Taxes - Other	0	48
49	Deferred Taxes - Fixed Assets	26,821	49
50	Total Federal Income Tax	65,429	50

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Expense Summary - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Expenses in 2000 Dollars		
1	Production (Generation)		1
2	Labor	0	2
3	Materials and Services	0	3
4	Other	0	4
5	Total	0	5
6	Transmission and Storage		6
7	Labor	2,514	7
8	Materials and Services	842	8
9	Other	0	9
10	Total	3,356	10
11	Distribution		11
12	Labor	78,095	12
13	Materials and Services	40,405	13
14	Other	0	14
15	Total	118,500	15
16	Customer Accounts		16
17	Labor	96,850	17
18	Materials and Services	46,418	18
19	Other	11,432	19
20	Total	154,700	20
21	Customer Service		21
22	Labor	1,919	22
23	Materials and Services	1,563	23
24	Other	0	24
25	Total	3,482	25
26	Administrative and General		26
27	Labor	23,987	27
28	Materials and Services	26,202	28
29	Other	44,542	29
30	Wage Related	6,416	30
31	Medical	16,961	31
32	Total	118,109	32
33	**Total Expenses in 2000 Dollars**		33
34	**Labor**	203,366	34
35	**Materials and Services**	115,430	35
36	**Other**	55,974	36
37	**Wage Related**	6,416	37
38	**Medical**	16,961	38
39	**Total**	398,147	39
40	**Total Expenses in 2003 Dollars**		40
41	**Labor**	223,823	41
42	**Materials and Services**	123,842	42
43	**Other**	55,974	43
44	**Wage Related**	7,061	44
45	**Medical**	71,957	45
46	**Total**	482,656	46

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Franchise Fees and Uncollectible Accounts Expenses - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenue		1
2	Rate Case Revenues	926,513	2
3	Percent Of Revenue From Customers	99.9813%	3
4	Rate Case Revenues From Customers	926,339	4
5	Uncollectible Accounts		5
6	Uncollectible Rate	0.002000	6
7	Uncollectible Accounts Expense	1,853	7
8	Franchise Fees		8
9	Rate Case Revenues From Customers	926,339	9
10	Uncollectible Accounts Expense	1,853	10
11	Net Rate Case Revenue From Customers	924,486	11
12	Franchise Rate	0.009673	12
13	Franchise Fees Expense	8,942	13

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Taxes Other than Income - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Property (Ad Valorem) Tax	21,100	1
2	Federal Insurance Contribution Act	15,165	2
3	Federal Unemployment Insurance	218	3
4	State Unemployment Insurance	573	4
5	San Francisco Payroll Tax	1,316	5
6	Total Payroll Taxes	17,272	6
7	Other Taxes	280	7
8	Total Taxes Other Than Income	38,652	8

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Plant In Service - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	2000 End-of-Year Plant		1
2	Functional	4,015,724	2
3	Common, General, and Intangible	870,593	3
4	Total 2000 End-of-Year Plant	4,886,317	4
5	2001 Full-Year Net Additions		5
6	Functional	145,732	6
7	Common, General, and Intangible	30,854	7
8	Total 2001 Net Additions	176,587	8
9	2001 End-of-Year Plant		9
10	Functional	4,161,456	10
11	Common, General, and Intangible	901,448	11
12	Total 2001 End-of-Year Plant	5,062,904	12
13	2002 Full-Year Net Additions		13
14	Functional	167,144	14
15	Common, General, and Intangible	29,550	15
16	Total 2002 Net Additions	196,694	16
17	2002 End-of-Year Plant		17
18	Functional	4,328,600	18
19	Common, General, and Intangible	930,998	19
20	Total 2002 End-of-Year Plant	5,259,597	20
21	2003 Full-Year Net Additions		21
22	Functional	170,955	22
23	Common, General, and Intangible	47,681	23
24	Total 2003 Net Additions	218,636	24
25	2003 End-of-Year Plant		25
26	Functional	4,499,555	26
27	Common, General, and Intangible	978,678	27
28	Total 2003 End-of-Year Plant	5,478,234	28
29	**2003 Weighted Average Net Additions**		29
30	Functional	78,312	30
31	Common, General, and Intangible	10,922	31
32	Total 2003 Weighted Average Net Additions	89,234	32
33	**2003 Weighted Average Plant**		33
34	Functional	4,406,911	34
35	Common, General, and Intangible	941,920	35
36	Total 2003 Weighted Average Plant	5,348,831	36

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Depreciation - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Depreciation		
1	Storage	565	1
2	Transmission	152	2
3	Distribution	128,057	3
4	General	1,033	4
5	Subtotal	129,808	5
6	Common Utility Allocation	45,421	6
7	Total	175,228	7
8	**Depreciation Reserve**		8
9	Storage	2,430	9
10	Transmission	913	10
11	Distribution	2,752,650	11
12	General	11,954	12
13	Subtotal	2,767,947	13
14	Common Utility Allocation	357,020	14
15	Total	3,124,967	15
	Weighted Average Depreciation Reserve		
16	Storage	2,147	16
17	Transmission	834	17
18	Distribution	2,702,561	18
19	General	11,791	19
20	Subtotal	2,717,333	20
21	Common Utility Allocation	350,526	21
22	Total	3,067,859	22

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied By Investors - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Operational Cash Requirements		
1	Required Bank Balances	0	1
2	Special Deposits and Working Funds	105	2
3	Other Receivables	14,565	3
4	Prepayments	1,795	4
5	Deferred Debits, Company-Wide	(182)	5
	Less		
6	Working Cash Capital not Supplied by Investors	2,297	6
7	Goods Delivered to Construction Sites	1,262	7
8	Accrued Vacation	0	8
	Add		
9	Prepayment, Departmental	(37,000)	9
10	Total Operational Cash Requirement	(24,277)	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	29,156	11
12	Working Cash Capital Supplied by Investors	4,879	12

Attachment D2
Pacific Gas and Gas Company
2003 General Rate Case
Rate Base - Test Year 2003
Gas Distribution
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	WEIGHTED AVERAGE PLANT		
1	Plant	5,348,831	1
2	Plant Held for Future Use	0	2
3	Common Plant - Allocation	0	3
4	Common Plant Held for Future Use	0	4
5	Total Weighted Average Plant	5,348,831	5
	WORKING CAPITAL		
6	Material and Supplies - Fuel	0	6
7	Material and Supplies - Other	2,714	7
8	Working Cash	4,879	8
9	Total Working Capital	7,593	9
	ADJUSTMENTS FOR TAX REFORM ACT		
10	Deferred Capitalized Interest	3,499	10
11	Deferred Vacation	10,339	11
12	Deferred CIAC Tax Effects	32,764	12
13	Total Adjustments	46,602	13
	LESS DEDUCTIONS		
14	Customer Advances	15,510	14
15	Accumulated Deferred Taxes - Defense	0	15
16	Accumulated Deferred Taxes - Fixed Assets	210,773	16
17	Accumulated Deferred Taxes - Other	0	17
18	Deferred ITC	30,887	18
19	Deferred Tax - Other	0	19
20	Total Deductions	257,170	20
21	DEPRECIATION RESERVE	3,067,859	21
22	TOTAL RATE BASE	2,077,996	22

Attachment D2
Pacific Gas and Electric Company
2003 General Rate Case
Net To Gross Multiplier - Test Year 2003
Gas Distribution

Line No.	Description	Adopted	Line No.
1	Revenue Base	1.000000	1
2	Less Interdepartmental Revenue	0.000187	2
3	Percent Revenue From Jurisdictional Customers	0.999813	3
4	Uncollectibles Percentage	0.002000	4
5	Franchise Requirements	0.009651	5
6	Total Uncollectibles and Franchise Requirements	0.011651	6
7	Net For State Income Taxes	0.988349	7
8	State Income Tax Percentage	0.088400	8
9	State Income Taxes	0.087370	9
10	Net For Federal Income Taxes	0.988349	10
11	Federal Income Tax Percentage	0.350000	11
12	Federal Income Taxes	0.345922	12
13	Net Operating Revenue	0.555057	13
14	Net To Gross Multiplier	1.801618	14

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Revenue Summary - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUES AT PRESENT RATES		
	CPUC Revenues (Retail)		
1	Revenues from Sales	872,700	1
2	Plus: Approved Other Operating Revenue	4,199	2
3	CPUC Revenue	876,899	3
4	Less: Non-Applicable Revenue	2,635	4
5	Rate Case Revenue	874,264	5
	FERC Revenues (Wholesale)		
6	Revenues from Sales	0	6
7	Plus: Other Operating Revenue	85	7
8	FERC Revenue	85	8
9	Less: Non-Applicable Revenue	85	9
10	Rate Case Revenue	0	10
11	Total Rate Case Revenue	874,264	11
	INCREASE IN RATE CASE REVENUE		
12	CPUC Jurisdiction	37,994	12
13	FERC Jurisdiction	0	13
14	Total Increase	37,994	14
15	Percent	4.35%	15
	INCREASE IN CPUC REVENUE FROM SALES		
16	Amount	34,034	16
17	Percent	3.90%	17
	REVENUES AT PROPOSED RATES		
	CPUC Revenues (Retail)		
18	Revenues from Sales	906,734	18
19	Plus: Other Operating Revenue	8,159	19
20	CPUC Revenue	914,893	20
21	Less: Non-Applicable Revenue	2,635	21
22	Rate Case Revenue	912,258	22
	FERC Revenues (Wholesale)		
23	Revenues from Sales	0	23
24	Plus: Other Operating Revenue	85	24
25	FERC Revenue	85	25
26	Less: Non-Applicable Revenue	85	26
27	Rate Case Revenue	0	27
28	Total Rate Case Revenue	912,258	28

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Results of Operations - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	REVENUE		
1	Revenue at Effective Rates	914,978	1
2	Less Non-General Revenue	2,720	2
3	General Rate Case Revenue	912,258	3
	OPERATING EXPENSES		
4	*Energy Costs	0	4
5	*Other Production	315,937	5
6	*Storage	0	6
7	*Transmission	3,850	7
8	*Distribution	0	8
9	*Customer Accounts	0	9
10	Uncollectibles	1,819	10
11	*Customer Services	0	11
12	*Administrative and General	91,765	12
13	Franchise Requirements	6,843	13
14	Amortization	7,771	14
15	Wage Change Impacts	19,016	15
16	Other Price Change Impacts	10,030	16
17	*Other Adjustments	0	17
18	Subtotal Expenses	457,030	18
	TAXES		
19	Superfund	0	19
20	Property	20,024	20
21	Payroll	15,549	21
22	Business	158	22
23	Other	95	23
24	State Corporation Franchise	18,238	24
25	Federal Income	84,247	25
26	Total Taxes	138,311	26
27	Depreciation	139,334	27
28	Fossil Decommissioning	26,499	28
29	Nuclear Decommissioning	0	29
30	Total Operating Expenses	761,174	30
31	Net for Return	151,084	31
32	Rate Base	1,635,951	32
	RATE OF RETURN		
33	On Rate Base	9.24%	33
34	On Equity	11.22%	34

* = Constant 2000 Dollars

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Income Tax Summary - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenues	912,258	1
2	O&M Expenses	457,030	2
3	Nuclear Decommissioning Expense	0	3
4	Superfund Tax	0	4
5	Taxes Other Than Income	35,826	5
6	Subtotal	419,401	6
	DEDUCTIONS FROM TAXABLE INCOME		
7	Interest Charges	57,237	7
8	Fiscal/Calendar Adjustment	5,691	8
9	Operating Expense Adjustments	(4,925)	9
10	Capitalized Interest Adjustment	0	10
11	Capitalized Inventory Adjustment	0	11
12	Vacation Accrual Reduction	(746)	12
13	Capitalized Other	187	13
14	Subtotal Deductions	57,444	14
	CCFT TAXES		
15	State Operating Expense Adjustment	1,920	15
16	State Tax Depreciation - Declining Balance	0	16
17	State Tax Depreciation - Fixed Assets	175,595	17
18	State Tax Depreciation - Other	0	18
19	Removal Costs	1,348	19
20	Repair Allowance	0	20
21	Subtotal Deductions	236,307	21
22	Taxable Income for CCFT	183,094	22
23	CCFT	16,186	23
24	State Tax Adjustment	0	24
25	Current CCFT	16,186	25
26	Defense Facilities Credit	(21)	26
27	Deferred Taxes - Interest	114	27
28	Deferred Taxes - Vacation	(67)	28
29	Deferred Taxes - Other	1,755	29
30	Deferred Taxes - Fixed Assets	271	30
31	Total CCFT	18,238	31
	FEDERAL TAXES		
32	CCFT - Prior Year	12,279	32
33	Federal Operating Expense Adjustment	2,811	33
34	Federal Tax Depreciation - Declining Balance	0	34
35	Federal Tax Depreciation - SLRL	0	35
36	Federal Tax Depreciation - Fixed Assets	143,059	36
37	Federal Tax Depreciation - Other	0	37
38	Removal Costs	151	38
39	Repair Allowance	0	39
40	Preferred Dividend Credit	2,321	40
41	Subtotal Deductions	218,065	41
42	Taxable Income for FIT	201,337	42
43	Federal Income Tax	70,468	43
44	Defense Facilities Credit	(77)	44
45	Flowback of Excess Deferred Taxes	0	45
46	Deferred Taxes - Interest	746	46
47	Deferred Taxes - Vacation	(237)	47
48	Deferred Taxes - Other	6,951	48
49	Deferred Taxes - Fixed Assets	6,397	49
50	Total Federal Income Tax	84,247	50

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Expense Summary - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Expenses in 2000 Dollars		
1	Production (Generation)		1
2	Labor	163,736	2
3	Materials and Services	140,459	3
4	Other	11,742	4
5	Total	315,937	5
6	Transmission		6
7	Labor	2,108	7
8	Materials and Services	1,743	8
9	Other	0	9
10	Total	3,850	10
11	Distribution		11
12	Labor	0	12
13	Materials and Services	0	13
14	Other	0	14
15	Total	0	15
16	Customer Accounts		16
17	Labor	0	17
18	Materials and Services	0	18
19	Other	0	19
20	Total	0	20
21	Customer Service		21
22	Labor	0	22
23	Materials and Services	0	23
24	Other	0	24
25	Total	0	25
26	Administrative and General		26
27	Labor	17,988	27
28	Materials and Services	19,319	28
29	Other	35,471	29
30	Wage Related	5,211	30
31	Medical	13,776	31
32	Total	91,765	32
33	**Total Expenses in 2000 Dollars**		33
34	**Labor**	183,832	34
35	**Materials and Services**	161,520	35
36	**Other**	47,213	36
37	**Wage Related**	5,211	37
38	**Medical**	13,776	38
39	**Total**	411,552	39
40	**Total Expenses in 2003 Dollars**		40
41	**Labor**	202,323	41
42	**Materials and Services**	167,538	42
43	**Other**	47,213	43
44	**Wage Related**	5,735	44
45	**Medical**	17,788	45
46	**Total**	440,598	46

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Franchise Fees and Uncollectible Accounts Expenses - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Revenue		1
2	Rate Case Revenues	912,258	2
3	Percent Of Revenue From Customers	99.6758%	3
4	Rate Case Revenues From Customers	909,300	4
5	Uncollectible Accounts		5
6	Uncollectible Rate	0.002000	6
7	Uncollectible Accounts Expense	1,819	7
8	Franchise Fees		8
9	Rate Case Revenues From Customers	909,300	9
10	Uncollectible Accounts Expense	1,819	10
11	Net Rate Case Revenue From Customers	907,482	11
12	Franchise Rate	0.007541	12
13	Franchise Fees Expense	6,843	13

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Taxes Other than Income - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	Property (Ad Valorem) Tax	20,024	1
2	Federal Insurance Contribution Act	13,708	2
3	Federal Unemployment Insurance	197	3
4	State Unemployment Insurance	518	4
5	San Francisco Payroll Tax	1,125	5
6	Total Payroll Taxes	15,549	6
7	Other Taxes	253	7
8	Total Taxes Other Than Income	35,826	8

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Plant In Service - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
1	2000 End-of-Year Plant		1
2	Functional	10,021,807	2
3	Common, General, and Intangible	383,098	3
4	Total 2000 End-of-Year Plant	10,404,905	4
5	2001 Full-Year Net Additions		5
6	Functional	77,548	6
7	Common, General, and Intangible	16,274	7
8	Total 2001 Net Additions	93,822	8
9	2001 End-of-Year Plant		9
10	Functional	10,099,355	10
11	Common, General, and Intangible	399,372	11
12	Total 2001 End-of-Year Plant	10,498,727	12
13	2002 Full-Year Net Additions		13
14	Functional	94,726	14
15	Common, General, and Intangible	21,427	15
16	Total 2002 Net Additions	116,154	16
17	2002 End-of-Year Plant		17
18	Functional	10,194,082	18
19	Common, General, and Intangible	420,799	19
20	Total 2002 End-of-Year Plant	10,614,881	20
21	2003 Full-Year Net Additions		21
22	Functional	110,662	22
23	Common, General, and Intangible	13,544	23
24	Total 2003 Net Additions	124,206	24
25	2003 End-of-Year Plant		25
26	Functional	10,304,743	26
27	Common, General, and Intangible	434,343	27
28	Total 2003 End-of-Year Plant	10,739,086	28
29	**2003 Weighted Average Net Additions**		29
30	Functional	57,399	30
31	Common, General, and Intangible	7,792	31
32	Total 2003 Weighted Average Net Additions	65,191	32
33	**2003 Weighted Average Plant**		33
34	Functional	10,251,481	34
35	Common, General, and Intangible	428,591	35
36	Total 2003 Weighted Average Plant	10,680,072	36

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Depreciation - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	Depreciation		
1	Production	112,164	1
2	Transmission	4,780	2
3	Distribution	-	3
4	General	1,615	4
5	Subtotal	118,559	5
6	Common Utility Allocation	20,775	6
7	Total	139,334	7
8	**Depreciation Reserve**		8
9	Production	8,548,724	9
10	Transmission	149,560	10
11	Distribution	-	11
12	General	25,932	12
13	Subtotal	8,724,215	13
14	Common Utility Allocation	200,710	14
15	Total	8,924,925	15
	Weighted Average Depreciation Reserve		
16	Production	8,455,111	16
17	Transmission	148,552	17
18	Distribution	-	18
19	General	25,454	19
20	Subtotal	8,629,117	20
21	Common Utility Allocation	195,889	21
22	Total	8,825,006	22

Attachment D3
Pacific Gas and Electric Company
2003 General Rate Case
Rate Base - Test Year 2003
Electric Generation
(Thousands of Dollars)

Line No.	Description	Adopted	Line No.
	WEIGHTED AVERAGE PLANT		
1	Plant	10,680,072	1
2	Plant Held for Future Use	0	2
3	Common Plant - Allocation	0	3
4	Common Plant Held for Future Use	0	4
5	Total Weighted Average Plant	10,680,072	5
	WORKING CAPITAL		
6	Material and Supplies - Fuel	51,722	6
7	Material and Supplies - Other	63,009	7
8	Working Cash	0	8
9	Total Working Capital	114,731	9
	ADJUSTMENTS FOR TAX REFORM ACT		
10	Deferred Capitalized Interest	5,371	10
11	Deferred Vacation	9,535	11
12	Deferred CIAC Tax Effects	0	12
13	Total Adjustments	14,906	13
	LESS DEDUCTIONS		
14	Customer Advances	0	14
15	Accumulated Deferred Taxes - Defense	48	15
16	Accumulated Deferred Taxes - Fixed Assets	415,180	16
17	Accumulated Deferred Taxes - Other	(74,002)	17
18	Deferred ITC	7,525	18
19	Deferred Tax - Other	0	19
20	Total Deductions	348,752	20
21	DEPRECIATION RESERVE	8,825,006	21
22	TOTAL RATE BASE	1,635,951	22

Attachment D4
Pacific Gas and Electric Company
2003 General Rate Case
Comparison of Revenue Requirements
Attrition Years 2004 Through 2006
(Thousands of dollars)

Line No.			2003	2004	2005	2006		Line No.
1	**Revenue Requirement**							1
2	Electric Distribution							2
3	Distribution Settlement	*	2,493,034	2,555,360	2,619,244	2,708,298		3
4	Gas Distribution							4
5	Distribution Settlement	*	926,513	949,676	973,418	1,006,514		5
6	Generation							6
7	Distribution Settlement	*	912,258	967,864	958,441	991,028		7
8	**Annual Increase**						**Accumulated**	8
9	Electric Distribution							9
10	Distribution Settlement			62,326	63,884	89,054	403,800	10
11	Gas Distribution							11
12	Distribution Settlement			23,163	23,742	33,096	150,068	12
13	Generation							13
14	Distribution Settlement			55,606	(9,423)	32,587	180,560	14

* Settlement attrition calculations assume CPIs of 2.5%, 2.5%, and 2.4% in 2004, 2005, and 2006, respectively, consistent with the underlying escalation rates assumed in this GRC. Actual CPI forecasts to be used to calculate attrition will be determined in October of each year for the following year.

Attachment D5
Pacific Gas and Electric Company
2003 General Rate Case
2003 Administrative and General Expenses by Unbundled Cost Category
Comparison of Settlement With PG&E's and ORA's Comparison Exhibit Positions*
(Thousands of 2000 Dollars)

Line No.	Description	PG&E's Comparison Exhibit Position	Adopted	Difference	ORA's Comparison Exhibit Position
		[a]	[b]	[c] = [a-b]	[d]
1	Electric Distribution	268,178	208,838	59,340	196,206
2	Gas Distribution	152,825	118,109	34,716	109,917
3	Generation	119,162	91,765	27,397	82,840
4	Humboldt Nuclear Unit 3	2,938	2,311	627	1,900
5	Electric Transmission	52,220	35,050	17,170	33,700
6	Gas Transmission and Storage	47,171	39,515	7,656	26,677
7	Electric Public Purpose Programs	90,271	87,505	2,766	86,783
8	Gas Public Purpose Programs	3,003	2,302	701	2,142
9	**Total Utility**	735,767	585,393	150,374	540,165

* PG&E's and ORA's Comparison Exhibit amounts reflect the corrected O&M labor factors submitted in Exhibit 100-B (page F-45).

Attachment D5
Pacific Gas and Electric Company
2003 General Rate Case Settlement Agreement
2003 Weighted Average Plant and Reserve
Allocation of Common, General and Intangible by Unbundled Cost Category
(Thousands of Dollars)

Description	Electric Distribution	Gas Distribution	Generation	Humboldt Nuclear Unit 3	Electric Transmission	Gas Transmission and Storage	Electric Public Purpose Programs	Gas Public Purpose Programs	Total
2003 WAVG Plant									
Direct Assigned									
Common	879,151	653,241	115,431	-	75,039	32,619	(2)	(1)	1,755,477
General	76,019	16,157	22,211	-	20,138	43,583	(3)	(1)	178,105
Intangible	8,656	1,101	67,963	-	1,000	15,317	-	-	94,036
Total C,G,&I	963,825	670,498	205,605	-	96,176	91,519	(5)	(1)	2,027,617
Residual									
Common	458,744	264,322	214,889	4,765	72,167	55,244	21,661	5,320	1,097,112
General	17,286	7,099	8,097	180	2,719	1,484	816	143	37,824
Intangible	-	-	-	-	-	-	-	-	-
Total C,G,&I	476,029	271,421	222,986	4,945	74,886	56,728	22,477	5,463	1,134,935
Total Direct Assigned and Residual									
Common	1,337,894	917,562	330,320	4,765	147,206	87,863	21,659	5,319	2,852,589
General	93,304	23,256	30,308	180	22,857	45,067	813	142	215,928
Intangible	8,656	1,101	67,963	-	1,000	15,317	-	-	94,036
Total C,G,&I	1,439,855	941,920	428,591	4,945	171,062	148,247	22,472	5,462	3,162,553

Description	Electric Distribution	Gas Distribution	Generation	Humboldt Nuclear Unit 3	Electric Transmission	Gas Transmission and Storage	Electric Public Purpose Programs	Gas Public Purpose Programs	Total
2003 WAVG Reserve									
Direct Assigned									
Common	364,983	261,228	94,213	-	33,434	12,759	-	-	766,617
General	37,999	8,214	19,691	-	3,053	11,728	-	-	80,685
Intangible	6,145	834	11,276	-	1,644	10,707	-	-	30,606
Total C,G,&I	409,127	270,276	125,180	-	38,131	35,194	-	-	877,908
Residual									
Common	155,177	89,299	101,676	1,612	24,412	18,664	7,327	1,797	399,963
General	12,304	3,577	5,764	128	1,936	748	581	72	25,108
Intangible	-	-	-	-	-	-	-	-	-
Total C,G,&I	167,481	92,876	107,439	1,740	26,347	19,411	7,908	1,869	425,071
Total Direct Assigned and Residual									
Common	520,160	350,526	195,889	1,612	57,845	31,423	7,327	1,797	1,166,580
General	50,303	11,791	25,454	128	4,989	12,476	581	72	105,794
Intangible	6,145	834	11,276	-	1,644	10,707	-	-	30,606
Total C,G,&I	576,607	363,152	232,620	1,740	64,478	54,605	7,908	1,869	1,302,980

Attachment D5
Pacific Gas and Electric Company
2003 General Rate Case Adopted
O&M LABOR FACTORS BY UNBUNDLED COST CATEGORY
(Thousands of 2000 Dollars)

Line	Unbundled Cost Category	Recorded Adjusted 2002 O&M Labor Expense $	Percentage
	Electric Generation		
1	EG - Fossil Facilities	9,972	1.24%
2	EG - Hydro Facilities	39,261	4.88%
3	EG - Diablo Canyon	108,091	13.43%
4	EG - Humboldt Unit 3	3,489	0.43%
5	EG - Purchased Power Payments	0	0.00%
6		160,813	19.99%
	Electric Transmission		
7	ET - Electric Network Transmission	52,311	6.50%
8	ET - Third-Party Generation-Ties	523	0.07%
9	ET - Partnership Generation-Ties	0	0.00%
10		52,835	6.57%
	Electric Distribution		
11	ED - Wires and Services	325,246	40.42%
12	ED - Electric Transactions Administration	10,610	1.32%
13		335,856	41.74%
	Electric Public Purpose Programs		
14	EP - Electric Public Purpose Programs	15,858	1.97%
15		15,858	1.97%
16	**Electric Total**	565,362	70.26%
	Gas Transmission		
17	GT - Gas Storage Services	5,386	0.67%
18	GT - Transmission: Line 401	1,222	0.15%
19	GT - Transmission: Non-Line 401	35,089	4.36%
20		41,698	5.18%
	Gas Distribution		
21	GD - Pipes and Services	190,985	23.74%
22	GD - Gas Procurement Administration	2,674	0.33%
23		193,659	24.07%
	Gas Public Purpose Programs		
24	GP - Gas Public Purpose Programs	3,898	0.48%
25		3,898	0.48%
26	**Gas Total**	239,255	29.74%
27	**Total Company**	804,617	100.00%

Attachment D6
Pacific Gas and Electric Company
2003 General Rate Case
Electric Distribution and Electric Transmission Depreciation Parameters

Asset Class	Account Title	Adopted Avg. Service Life	Adopted Curve Type
Electric	**Transmission**		
ETP35201	Structures & Improvements	50	S6
ETP35202	Structures & Improvements/Eq.	50	S6
ETP35301	Station Equipment	40	S3
ETP35302	Step Up Transformers	-	-
ETP35400	Tower & Fixtures	70	S4
ETP35500	Poles & Fixtures	42	R3
ETP35600	OH Conductor/Devices	52	S6
ETP35700	UG Conduit	60	R5
ETP35800	UG Conductor/Devices	50	R3
ETP35900	Roads & Trails	60	R5
Electric	**Distribution**		
EDP36101	Structures & Improvements	55	L5
EDP36102	Structures & Improvements-Eq.	55	L5
EDP36200	Station Equipment	39	R2
EDP36300	Storage Battery	10	-
EDP36400	Poles, Towers & Fixtures	40	L0.5
EDP36500	OH conductors & Devices	38	R1
EDP36600	Underground Conduit	58	L3
EDP36700	UG Conductors & Devices	31	R5
EDP36801	Line Transformers-Overhead	31	S1
EDP36802	Line Transformers-Underground	34	S1
EDP36901	Services-Overhead	45	R2
EDP36902	Services-Underground	43	R4
EDP37000	Meters	27	R2
EDP37100	Installation on Cust. Premises	36	S1
EDP37200	Leased Property on Cust. Prem.	16	S1
EDP37301	Street Light-Overhead Cond.	28	R0.5
EDP37302	Street Light-Conduit & Cables	29	L2
EDP37303	Street Light-Lamps & Eq.	20	L0
EDP37304	Street Light-Electroliers	19	S6

Attachment D6
Pacific Gas and Electric Company
2003 General Rate Case
Electric Distribution and Electric Transmission Depreciation Parameters

Asset Class	Account Title	Adopted Net Salvage %
Electric	Transmission	
ETP35201	Structures & Improvements	-10
ETP35202	Structures & Improvements/Eq.	-5
ETP35301	Station Equipment	0
ETP35302	Step Up Transformers	0
ETP35400	Tower & Fixtures	-40
ETP35500	Poles & Fixtures	-50
ETP35600	OH Conductor/Devices	-31
ETP35700	UG Conduit	0
ETP35800	UG Conductor/Devices	0
ETP35900	Roads & Trails	0
Electric	**Distribution**	
EDP36101	Structures & Improvements	-10
EDP36102	Structures & Improvements-Eq.	0
EDP36200	Station Equipment	0
EDP36300	Storage Battery	0
EDP36400	Poles, Towers & Fixtures	-35
EDP36500	OH conductors & Devices	-49
EDP36600	Underground Conduit	10
EDP36700	UG Conductors & Devices	-19
EDP36801	Line Transformers-Overhead	10
EDP36802	Line Transformers-Underground	0
EDP36901	Services-Overhead	-60
EDP36902	Services-Underground	-40
EDP37000	Meters	0
EDP37100	Installation on Cust. Premises	0
EDP37200	Leased Property on Cust. Prem.	75
EDP37301	Street Light-Overhead Cond.	-95
EDP37302	Street Light-Conduit & Cables	-10
EDP37303	Street Light-Lamps & Eq.	-10
EDP37304	Street Light-Electroliers	0

Attachment D6
Pacific Gas and Electric Company
2003 General Rate Case
Gas Distribution Depreciation Parameters

Asset Class	Account Title	Adopted Avg. Service Life	Adopted Curve Type
GDP37500	Structures & Improvements	49	R2
GDP37601	Mains	54	S3
GDP37700	Compressor Station Equipment	24	R1.5
GDP37800	Odorizing/Meas & Reg Sta Equipment	37	R2.5
GDP38000	Services	50	R3
GDP38100	Meters	24	R1.5
GDP38300	House Regulators	23	R1.5
GDP38500	Meas & Reg Sta Equip-Industrial	34	R2
GDP38600	Other Property on Customer Premises	35	R2
GDP38700	Other Equipment	28	S0

Attachment D6
Pacific Gas and Electric Company
2003 General Rate Case
Gas Distribution Depreciation Parameters

Asset Class	Account Title	Adopted Net Salvage %
GDP37500	Structures & Improvements	-20
GDP37601	Mains	-45
GDP37700	Compressor Station Equipment	-10
GDP37800	Odorizing/Meas & Reg Sta Equipment	-55
GDP38000	Services	-85
GDP38100	Meters	0
GDP38300	House Regulators	0
GDP38500	Meas & Reg Sta Equip-Industrial	-15
GDP38600	Other Property on Customer Premises	0
GDP38700	Other Equipment	0

(END OF ATTACHMENT D)

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(END OF ATTACHMENT E)