Pacific Gas and Electric Company

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Shir Kochavi
Attorney at Law

77 Beale Street, Room 3082
San Francisco, CA 94105

Mailing Address
P.O. Box 7442
San Francisco, CA 94120

415.973.2777
Fax: 415.973.5520

April 18, 2002

02 APR 19 AM 9:44
FEDERAL ENERGY REGULATORY COMMISSION

Ms. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Offer of Settlement in Docket Nos. ER02-11-000 and ER02-208-000

Dear Ms. Salas:

In accordance with the provisions of Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §385.602, Pacific Gas and Electric Company ("PG&E") and the California Independent System Operator ("ISO") hereby submit for filing and acceptance an original and fourteen copies of the settlement materials described below. The Offer of Settlement has been negotiated with all active parties in the above-captioned proceedings and is intended to resolve all issues therein. The Offer of Settlement is being filed as a settlement offer to all parties in these dockets.

The following documents are attached:

1. An Explanatory Statement;
2. The Offer of Settlement;
3. Exhibit A to the Offer of Settlement: supporting workpapers showing the calculation of the revised Annual Fixed Revenue Requirement for each of the listed power plants;
4. Exhibit B to the Offer of Settlement: proposed modifications to the rate schedules listed below, in redline and clean format, in accordance with the terms of the Offer of Settlement:

   Helms Power Plant, PG&E Rate Schedule FERC No. 207,
   Humboldt Bay Power Plant, PG&E Rate Schedule FERC No. 208,
   Hunters Point Power Plant, PG&E Rate Schedule FERC No. 209, and
   San Joaquin Power Plant, PG&E Rate Schedule FERC No. 211.

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5. A draft Commission letter order approving the settlement (with diskette on WordPerfect format); and
6. A certificate of service certifying that the settlement materials were served in accordance with the requirements of Rule 602(d) of the Commission's Rules of Practice and Procedure.

Pursuant to 18 C.F.R. § 385.602, any comments on the Offer of Settlement may be filed with the Secretary by May 9, 2002. Reply comments may be filed with the Secretary by May 19, 2002.

PG&E hereby submits an additional copy of this transmittal letter and respectfully requests that the Commission acknowledge receipt of this document by returning this copy endorsed as filed in the enclosed stamped, pre-addressed envelope.

Respectfully submitted,

Shiran Kochavi

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-2777

Attachments and Enclosures

EXPLANATORY STATEMENT

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REGULATORY COMMISSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	Docket Nos. ER02-11-000 and
Pacific Gas and Electric Company	)	ER02-208-000
	)	(Not Consolidated)

EXPLANATORY STATEMENT

As required by Rule 602(c)(ii) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.602(c)(ii) (2001), Pacific Gas and Electric Company ("PG&E") and the California Independent System Operator Corporation ("ISO") (collectively, the "Sponsoring Parties") hereby submit this Explanatory Statement to explain the basis for and significance of the Offer of Settlement attached hereto (the "Settlement"). The Settlement is intended to resolve all issues in Docket Nos. ER02-11-000 and ER02-208-000. The Settlement has been reviewed and is not opposed by any of the parties.[1] This Explanatory Statement is not intended to alter any of the provisions of the Settlement and is provided solely for compliance with Rule 602(c)(ii) of the Rules of Practice and Procedure of the Commission.

I. PROCEDURAL HISTORY

A. Background

On May 28, 1999, the Commission approved a settlement ("Interim Stipulation") adopting a *pro forma* RMR Agreement ("RMR Agreement")[2] to govern the terms and conditions under which

[1] Other than the Sponsoring Parties, the parties in Docket No. ER02-11-000 include, as interveners, (i) Southern California Edison Company; (ii) Three Mountain Power, LLC; (iii) Mirant Americas Energy, LP, Mirant California, LLC, Mirant Delta, LLC and Mirant Potrero, LLC; (iv) the California Public Utilities Commission ("CPUC"); (v) the California Electricity Oversight Board ("EOB"); and (vi) the City and County of San Francisco. Other than the Sponsoring Parties, the only parties in Docket No. ER02-208-000 are the CPUC, the EOB and the City and County of San Francisco. The staff of the CPUC will recommend to the full CPUC that it submit supporting comments regarding the Settlement. The EOB may also submit supporting comments regarding the Settlement.

[2] Because the generating units covered by these agreements must operate at certain times for the reliability of the transmission grid, they are referred to as "reliability must-run" or "RMR" units and the agreements covering them are referred to as "RMR Agreements."

each owner of an RMR Unit provides RMR services to the ISO. The Interim Stipulation requires that each owner of an RMR Unit, including PG&E, provide RMR services under individual rate schedules that incorporate the RMR Agreement and rates specific to each RMR Unit. Among the RMR Agreement's provisions is the requirement that, whenever the ISO extends the term of the RMR Agreement for an additional calendar year, the RMR Owner will make an annual Federal Power Act filing updating certain rates and terms of service. PG&E and the ISO have 2002 RMR Agreements ("PG&E RMR Agreements") for Helms Power Plant ("Helms"), Humboldt Bay Power Plant ("Humboldt Bay"), Hunters Point Power Plant ("Hunters Point") and San Joaquin Power Plant ("San Joaquin"). Docket Nos. ER02-11-000 and ER02-208-000 pertain to revisions to certain rates and terms of service of the PG&E RMR Agreements.

B. ER02-11-000.

On October 1, 2001, PG&E submitted an informational rate filing proposing rate revisions under the PG&E RMR Agreements ("Informational Filing"). The Informational Filing was intended to comply with the terms of the Interim Stipulation, under which each RMR Owner is required to adjust rates annually, beginning with calendar year 2002, using the rate formula set forth in Schedule F of the RMR Agreement. Schedule F establishes the procedures and methodology for determining the Annual Fixed Revenue Requirements ("AFRR") and Variable Operations and Maintenance Rates ("Variable O&M Rates") for facilities designated for must-run service.[3] The Informational Filing provided updated cost information for use in determining the AFRR and the Variable O&M Rates for the PG&E RMR Agreements, to be effective January 1, 2002.

On October 22, 2001, the ISO, CPUC and EOB ("Protesters"), each in a separate filing,

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[3] Schedule F, "Determination of Annual Revenue Requirements of Must-Run Generating Units", of the RMR Agreements ("Schedule F") "...establishes the procedures and methodology for determining the Annual Fixed Revenue Requirements (in dollars) and Variable O&M Rates (in $/MWh) for facilities designated for must-run service..." using a "Rate Formula." Schedule F states, "On or before October 1, 2001, the Owner shall provide to the ISO [an] Information Package relating to the rates and charges to become effective on January 1, 2002."

intervened and protested the Informational Filing. On October 23, 2001, the Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to December 14, 2001.

On December 5, 2001, the Sponsoring Parties, the EOB and the CPUC (collectively, the "Joint Parties") jointly moved to extend the protest deadline in the docket to January 10, 2002. In the same filing, the Protesters withdrew without prejudice the protests they filed on October 22, 2001. Additionally, in the same filing, the Joint Parties agreed that the rates filed by PG&E in Docket ER02-208-000 could go into effect, subject to refund, on January 1, 2002. On December 19, 2001, the Commission issued a Notice of Extension of Time, extending the time for filing protests in the docket to January 10, 2002. On January 10, 2002, the Joint Parties jointly moved to further extend the protest deadline to February 15, 2002. On January 30, 2002, the Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to February 15, 2002. On February 14, 2002, the Joint Parties again jointly moved to further extend the protest deadline to March 1, 2002. On February 28, 2002, the Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to March 1, 2002.

On March 1, 2002, the Protesters protested the Informational Filing. The Protesters contended that the AFRR values in the Informational Filing were unjust and unreasonable, and contested certain aspects of PG&E's calculations. In the protest, the Protesters also requested that the Commission defer taking any action in this matter until April 1, 2002, or later, so that the Joint Parties could continue ongoing settlement discussions.

C. ER02-208-000.

On October 31, 2001, PG&E filed an annual update to certain operating data and rates in Docket No. ER02-208-000 ("Rate Filing"). The Rate Filing was intended to comply with the terms of the RMR Agreement under which each RMR Owner is required to file annual updates for certain provisions of the RMR Agreement. On November 21, the Protesters, each in a separate motion, intervened and protested the Rate Filing. Protesters' principal objection was to the Rate Filing's inclusion of the same AFRR values and Variable O&M Rates that Protesters were contesting in Docket No. ER02-11-000. The Rate Filing did include changes to rates based on the AFRR values proposed in Docket No. ER02-11-000. On December 19, 2001, the Commission accepted and nominally suspended the Rate Filing, subject to the outcome of the proceeding in Docket No. ER02-11-000 and subject to refund, effective January 1, 2002.

II. DESCRIPTION OF SETTLEMENT

A. Key Settlement Provisions.

1. <u>ER02-11-000</u>

The purpose of PG&E's Informational Filing was to generate AFRR values and Variable O&M rates to include in PG&E's Rate Filing. Contested components of the Informational Filing's AFRR calculation were: (i) annual depreciation, (ii) original plant cost, (iii) depreciation reserve, (iv) annual capital additions, and (v) O&M expenses for Hunters Point Units 2 and 3. The settlement discussions between the Sponsoring Parties and the resulting Settlement have resolved all of these items as described below.

(i) Depreciation: PG&E's filing used recorded depreciation for the period July 1, 2000, through June 30, 2001, which included an accelerated depreciation component.[4] The settlement negotiations resulted in a switch from the accelerated depreciation methodology to a "normal" --i.e., unaccelerated -- depreciation methodology in calculating the RMR facilities' AFRR.

(ii) Original Plant Cost: The Informational Filing included PG&E's RMR facilities' capital numbers as of June 30, 2001. The capital data was prepared by PG&E's Capital Accounting Department. The same data source is used when PG&E prepares its FERC Form No. 1 report with the exception of the depreciation reserve. A plant's capital includes both generation assets (e.g., boilers) and non-generation assets (e.g., on-site step-up transformer). In addition, a plant's capital also includes a share of common and general plant capital. In the settlement discussions, the Sponsoring Parties agreed to exclude both the non-generation plant capital and common and general plant capital from the AFRR calculations.

(iii) Depreciation Reserve: The use of accelerated depreciation, as described in II.A.1(i) above, had a dollar for dollar effect on the size of the depreciation reserve used in PG&E's Informational Filing. Settlement negotiations resulted in continuing to use the restated depreciation reserve included in PG&E's Informational Filing for Hunters Point and Humboldt Bay, with the only changes being minor corrections to errors discovered during the discovery process. For Helms Pumped Storage, the settlement negotiations resulted in a switch to from the accelerated depreciation methodology to a "normal" --i.e., unaccelerated -- depreciation methodology in the AFRR calculation of depreciation reserve.

[4] PG&E believes this accelerated depreciation to be in compliance with CPUC order directed in D.01-03-082 (March 27, 2001). The compliance filing for this order is contained in Advice Letter 2130-E (filed with the CPUC June 25, 2001). The CPUC has not acted on this Advice Letter.

(iv) Capital Additions: Capital additions for RMR facilities are recovered through a rate surcharge separate from the AFRR. Thus, all capital additions since the beginning of the RMR Agreements should be excluded from the capital numbers. Inadvertently, this was not done in the Informational Filing. During the course of discovery and settlement discussions, this error was corrected and inappropriate capital additions were excluded from the AFRR calculations.

(v) Hunters Point Units 2 and 3, O&M Expenses: During 2001, PG&E converted Units 2 and 3 at Hunters Point from steam generators to synchronous condensers. Hence, the historical costs for these units, which were included in the Informational Filing, did not provide an accurate benchmark from which to forecast the units' future costs. In the settlement discussions, the Sponsoring Parties agreed to replace the O&M costs for Hunters Point Units 2 and 3 with O&M costs previously submitted in a settlement filed with FERC on August 9, 2001, in Docket No. ER01-2810-000,[5] and accepted for filing in a letter order dated October 3, 2001.[6]

The Settlement's AFRR values compared to the Informational Filing's AFRR values are shown in Table 1 below. These values are based on the resolution of the issues described above.

TABLE 1
2002 AFRR (in dollars)

Facility	Informational Filing	Settlement
Helms	170,924,230	101,873,022
San Joaquin	27,562,672	26,933,123
Hunters Point	38,813,141	24,615,715
Humboldt Bay	8,763,611	9,580,968

[5] "Pacific Gas and Electric Company Submits Revisions to Hunters Point Power Plant Rates and Performance Characteristics Under Reliability Must-Run Service Agreement with California Independent System Operator Corporation under ER01-2810," filed August 9, 2001, in Docket No. ER01-2810-000.

[6] "Letter order accepting Pacific Gas & Electric Company's August 9, 2001 filing of Original Sheet 118A et al to First Revised FERC, Electric Rate Schedule 209, with California Independent System Operator Corporation under ER01-2810" (October 3, 2001)

2. ER02-208-000

On October 31, 2001, PG&E filed its Rate Filing. The rates and charges in Schedule B are calculated values based on the AFRR for each facility. Therefore, when the AFRR changes, the rates and charges must change as well. The Informational Filing proposed changes to the AFRR values while the Rate Filing was the vehicle for incorporating the changes into the RMR rates and charges. The Settlement rates and charges have been modified from the values in Docket ER02-208-000 only to the extent required by changes to the AFRR values, except for Hunters Point Units 2&3.

The Target Available Hours ("TAH") for Hunters Point Units 2 and 3 were inadvertently incorrectly calculated in the Rate Filing. The Rate Filing included "Annual Other Outage Hours" for Units 2 and 3 from when they were steam generators. This caused the TAH to be underestimated considering that the units are now synchronous condensers. This oversight was corrected in the discovery and settlement process. The Sponsoring Parties have agreed to calculate TAH using the "Annual Other Outage Hours" from the August 9, 2001, filing in Docket ER01-2810-000[6] and the "Planned Outage Hours" from the Rate Filing.

B. Other Provisions

1. Approval and Effective Date

The Settlement is contingent upon Commission approval of the Settlement. The effective date of the Settlement will be the date the Commission approved the Settlement without modification or condition, or, if modified, or conditioned, upon the date of acceptance of all signatories hereto.

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[6] *Id.*

2. The Settlement is made upon the express understanding that it constitutes a negotiated settlement and cannot be cited as precedent or relied upon in any manner. Further, no party to the Settlement shall use another party's acquiescence to the Settlement as evidence of the settling party's agreement to, or support of, any principle in litigation.

Dated: April 18, 2002

Respectfully submitted,

STUART K. GARDINER
SHIRAN KOCHAVI

By: ______________________
SHIRAN KOCHAVI

Attorneys for
Pacific Gas and Electric Company
Law Department, B30A
Post Office Box 7442
San Francisco, CA 94120
Telephone: (415) 973-2777
Facsimile: (415) 973-5520

OFFER OF SETTLEMENT

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REGULATORY COMMISSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company	)))	Docket Nos. ER02-11-000 and ER02-208-000 (Not Consolidated)

OFFER OF SETTLEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.602 (2001), Pacific Gas and Electric Company ("PG&E") and the California Independent System Operator Corporation ("ISO") (collectively, the "Sponsoring Parties") submit this Offer of Settlement ("Settlement") in final settlement of all issues in Docket Nos. ER02-11-000 and ER02-208-000. Unless otherwise defined herein, capitalized terms used in the Settlement shall have the same meaning as those terms defined in the Must-Run Service Agreements between PG&E and the ISO[1] ("PG&E RMR Agreements"), and in the Master Definitions Supplement, Appendix A of the ISO Tariff.

Approval of the Settlement would avoid unnecessary and costly litigation, eliminate regulatory uncertainty, and promote administrative efficiency. Accordingly, approval of this Settlement is in the public interest.

I. PROCEDURAL HISTORY

On May 28, 1999, the Commission approved a settlement adopting a *pro forma* RMR Agreement ("RMR Agreement") to govern the terms and conditions under which each owner of an RMR Unit provides RMR services to the ISO ("Interim Stipulation").[2] Each of the Sponsoring Parties is also a "Sponsoring Party" as defined in the Interim Stipulation. The Interim Stipulation requires that each owner of an RMR Unit, including PG&E, provide RMR

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[1] PG&E and the ISO have RMR Agreements for the Helms Power Plant ("Helms"), Humboldt Bay Power Plant ("Humboldt Bay"), Hunters Point Power Plant ("Hunters Point") and San Joaquin Power Plant ("San Joaquin").

services under individual rate schedules that incorporate the RMR Agreement, and rates specific to each RMR Unit. Among the RMR Agreement's provisions is the requirement that, whenever the ISO extends the term of the RMR Agreement for an additional calendar year, the RMR Owner will make an annual Federal Power Act[3] filing updating certain rates and terms of service.

A. ER02-11-000.

On October 1, 2001, PG&E submitted an informational rate filing proposing rate revisions under the PG&E RMR Agreements ("Informational Filing")[4]. The Informational Filing was intended to comply with the terms of the Interim Stipulation, under which each RMR Owner is required to adjust rates annually, beginning with calendar year 2002, using the rate formula set forth in Schedule F of the RMR Agreement. Schedule F establishes the procedures and methodology for determining the Annual Fixed Revenue Requirements ("AFRR") and Variable Operations and Maintenance Rates ("Variable O&M Rates") for facilities designated for must-run service. The Informational Filing provided updated cost information for use in determining the AFRR and the Variable O&M Rates to be effective January 1, 2002, for the PG&E RMR Agreements. On October 22, 2001, the ISO, the California Public Utilities Commission ("CPUC") and the California Electricity Oversight Board ("EOB"), each in a separate motion, intervened and protested the Informational Filing.[5] On October 23, 2001, the

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[2] *California Independent System Operator Corp.*, 87 FERC ¶ 61,250 (1999).

[3] 16 U.S.C. §§ 791a-825r (2002).

[4] "Pacific Gas and Electric Company Submits an Informational Rate Filing and Proposal for Revised Values Related to Its Reliability Must Run Service Agreements With California Independent System Operator Corporation under ER02-11," filed October 1, 2001, in Docket No. ER02-11-000.

[5] "Motion to Intervene and Protest of the California Independent System Operator Corporation and Motion for Extension of Time for Discovery and Protests," filed October 22, 2001, in Docket No. ER02-11-000; "Notice of Intervention and Protest of the Public Utilities Commission of the State of California," filed October 22, 2001, in Docket No. ER02-11-000; "Motion to Intervene and Protest of the California Electricity Oversight Board," filed October 22, 2001, in Docket No. ER02-11-000.

Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to December 14, 2001.[6]

On December 5, 2001, the Sponsoring Parties, the EOB, and the CPUC (collectively, the "Joint Parties") jointly moved to extend the protest deadline in the Informational Filing to January 10, 2002.[7] In the same filing, the ISO, CPUC and EOB withdrew without prejudice the protests they filed on October 22, 2001. Additionally, in the same filing, the Joint Parties agreed that the rates filed by PG&E in Docket ER02-208-000 could go into effect, subject to refund, on January 1, 2002.[8] On December 19, 2001, the Commission issued a Notice of Extension of Time, extending the time for filing protests to the Informational Filing to January 10, 2002.[9] On January 10, 2002, the Joint Parties jointly moved to further extend the protest deadline to February 15, 2002.[10] On January 30, 2002, the Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to February 15, 2002.[11] On February 14, 2002, the Joint Parties again jointly moved to further extend the protest deadline to March 1, 2002.[12] On February 28, 2002, the Commission issued a Notice of Extension of Time, extending the time for filing protests and interventions in this matter to March 1, 2002.[13] On March 1, 2002, the CPUC, ISO and EOB protested the Informational

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6 "Notice of Extension of Time to and including 12/14/01 in Docket No. ER02-11-000" (October 23, 2001)

7 "Joint Motion by the California Independent System Operator Corporation, the California Public Utilities Commission, the California Energy Oversight Board and Pacific Gas and Electric Company to Extend the Protest Deadline," filed December 5, 2001, in Docket No. ER02-11-000.

8 See discussion in Section I.B.

9 "Notice of an Extension of Time to and including 1/10/02 01 in Docket No. ER02-11-000" (December 19, 2001)

10 "Joint Motion by the California Independent System Operator Corporation, the California Public Utilities Commission, the California Energy Oversight Board and Pacific Gas and Electric Company to Further Extend the Protest Deadline," filed January 10, 2002, in Docket No. ER02-11-000.

11 "Notice of Further Extension of Time for the Filing of Protests to and including February 15, 2002 in Docket No. ER02-11-000" (January 30, 2002).

12 "Joint Motion by the California Independent System Operator Corporation, the California Public Utilities Commission, the California Energy Oversight Board and Pacific Gas and Electric Company to Extend the Protest Deadline," filed February 14, 2002, in Docket No. ER02-11-000.

13 "Notice of Further Extension of Time for Filing of Protests to and including March 1, 2002 in Docket No. ER02-11-000" (February 28, 2002).

Filing.[14] In the protest, the CPUC, ISO and EOB requested that the Commission defer taking any action in this matter until April 1, 2002, or later, so that the Joint Parties could continue their ongoing settlement discussions.

B. ER02-208-000

On October 31, 2001, PG&E filed an annual update to certain operating data and rates in Docket No. ER02-208-000 ("Rate Filing").[15] The Rate Filing was intended to comply with the terms of the RMR Agreement under which each RMR Owner is required to file annual updates for certain provisions of the RMR Agreement. On November 21, the ISO, CPUC and EOB, each in a separate motion, intervened and protested the Rate Filing.[16] The Rate Filing included changes to rates based on the AFRR values proposed in Docket No. ER02-11-000. On December 19, 2001, the Commission accepted and nominally suspended the Rate Filing, subject to the outcome of the proceeding in Docket No. ER02-11-000 and subject to refund, effective January 1, 2002.[17]

II. TERMS OF SETTLEMENT

A. Effective Dates

1. The Effective Date of the Settlement is predicated upon, and the Settlement shall be effective, on the date the Commission shall have issued an order approving

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[14] "Protest of California Public Utilities Commission, California Independent System Operator Corporation, and California Electricity Oversight Board" filed March 1, 2002, in Docket No. ER02-11-000.

[15] "Pacific Gas and Electric Company Submits Revised Schedule Sheets for Its Reliability Must Run Service Agreements With California Independent System Operator Corporation under ER02-208," filed October 31, 2001, in Docket No. ER02-208-000.

[16] "Motion to Intervene and Conditional Protest of the California Independent System Operator Corporation," filed November 21, 2001, in Docket No. ER02-208-000; "Notice of Intervention and Protest of the Public Utilities Commission of the State of California," filed November 21, 2001, in Docket No. ER02-208-000; "Motion to Intervene and Protest by the California Electricity Oversight Board," filed November 21, 2001, in Docket No. ER02-208-000.

[17] "Order Conditionally Accepting Revised Rate Sheets in Docket No. ER02-08-000" (December 19, 2001).

the Settlement without modification or condition, or, if modified or conditioned, upon the date of acceptance of such order by all of the signatories hereto ("Effective Date").

2. The effective date for the rates and other rate schedule changes herein is January 1, 2002.

B. Settlement of AFRR Values, Variable O&M Rates and Target Available Hours.

1. This Settlement establishes an AFRR value for each of PG&E's four RMR facilities and replaces the AFRR values of the Informational Filing. The AFRR values of the Informational Filing and the final revised values are in Table 1 below. These values are based on assumptions negotiated and agreed to by the Joint Parties, which included significant changes in the depreciation rates, depreciation reserve and types of capital to be included in the calculation. The workpapers, attached as Exhibit A, show the allocation of each Facility's AFRR among Units at the Facility.

TABLE 1
2002 AFRR (in dollars)

Facility	Informational Filing	Settlement
Helms	170,924,230	101,873,022
San Joaquin	27,562,672	26,933,123
Hunters Point	38,813,141	24,615,715
Humboldt Bay	8,763,611	9,580,968

2. The Variable O&M Rates in the Settlement are identical to those in the Informational Filing.

3. The Target Available Hours (TAH) for Hunters Point Units 2&3 in the Settlement are based on the Annual Other Outage Hours, filed August 9, 2001, in Docket No.

ER01-2810-000,[18] and the Planned Outage Hours, filed October 31, 2001, in the Rate Filing.

III. IMPLEMENTATION OF STIPULATION

A. Upon issuance of a Commission Order approving this Settlement, all issues in Docket No. ER02-11-000 and ER02-208-000 shall be finally resolved.

B. Attached hereto as Exhibit A are the workpapers used to reach the Settlement.

C. Attached hereto as Exhibit B are revised rate sheets to the PG&E RMR Agreements which implement the provisions of this Settlement.

D. The Sponsoring Parties request the Commission to accept the revised rate sheets.

IV. WAIVER OF REHEARING

The Sponsoring Parties are PG&E and the ISO. A "Subject Party" is any party or participant that files initial comments supporting the Settlement without modification or condition or who elects not to file comments as permitted under the Commission's Rules of Practice and Procedure. Any party that files initial comments or reply comments on the Settlement, regardless of whether such party characterizes its comments as being in support of or in opposition to approval of the Settlement, shall be a "Contesting Party" if it requests any modification or condition to the terms set forth herein or to the PG&E RMR Agreements not revised by this Settlement.

Sponsoring Parties and Subject Parties hereby waive any and all rights to seek rehearing or judicial review of any Commission order(s) approving the Settlement, and shall be bound by and entitled to the benefits of the provisions of the Settlement; *provided, however*, that if the Commission approves this Settlement with modifications or conditions, a Sponsoring Party or

[18] "Pacific Gas and Electric Company Submits Revised Schedule Sheets for Its Reliability Must-Run Service Agreement with the California Independent System Operator Corporation for Hunters Point Power Plant under ER01-2810," filed August 9, 2001, in Docket No. ER01-2810-000.

Subject Party may seek rehearing or judicial review of the Commission's order(s) approving the Settlement solely to challenge the Commission's imposition of modifications or conditions in order to preserve the terms and conditions of this Settlement as filed.

V. RESERVATIONS

Agreement to or acquiescence in the Settlement shall not be deemed in any respect to constitute an admission by any party hereto that any allegation or contention made by any other party in these proceedings is true or valid. In reaching the Settlement, the parties specifically agree that the Settlement represents a negotiated agreement for the sole purpose of settling certain issues, as described herein, in the captioned dockets. The Commission's approval of the Settlement shall not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

The parties agree that the resolution of any matter in the Settlement shall not be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of the State of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

The discussions among the parties that have produced the Settlement have been conducted on the explicit understanding that they were undertaken subject to Rule 602(e) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(e) (2001), and the rights of the parties with respect thereto shall not be impaired by the Settlement.

Notwithstanding any provision of the Settlement, nothing herein is intended to limit or affect the rights and remedies of the parties with respect to any claim that the amounts invoiced under the PG&E RMR Agreements do not comply with the provisions of the PG&E RMR Agreements.

Nothing in this Settlement is intended to compromise or in any way to affect the allegations or contentions of the various parties in any other Commission docket, including but not limited to Docket No. EL02-20-000.

VI. MISCELLANEOUS PROVISIONS

A. Headings

The titles and headings of the various Articles and Sections in this Settlement are for reference purposes only. They are not to be construed or taken into account in interpreting this Settlement, and do not qualify, modify, or explain the effects of this Settlement.

B. Successors and Assigns

The rights conferred and obligations imposed on any party by this Settlement shall inure to the benefit of or be binding on that party's successors in interest or assignees as if such successor or assignee was itself a party hereto.

C. Counterparts

This Settlement may be executed in counterparts.

Dated: 4-18-02

JEANNE M. SOLÉ /sk
Jeanne M. Solé
Attorney for the California Independent System Operator Corporation

Dated: 4-18-02

Shiran Kochavi
Attorney for Pacific Gas and Electric Company

02 APR 19 AM 9:45
REGULATORY COMMISSION

EXHIBIT A

FOR SETTLEMENT PURPOSES ONLY

The following rules and sections apply to this document:

Rule 51 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice,
Rule 408 of the Federal Rules of Evidence,
Section 1152 of the California Evidence Code

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001

Final CPUC requested analysis of 2002 AFRR

	Current 2001 AFRR $	Filed 2002 AFRR $	Final CPUC requested** Analysis of 2002 AFRR $	Change from filing
Total	**$ 164,290,676**	**$ 246,063,654**	**$ 163,002,829**	**$ (83,060,825)**
Helms	**$ 105,848,601**	**$ 170,924,230**	**$ 101,873,022**	**$ (69,051,208)**
San Joaquin Watershed	**$ 23,411,098**	**$ 27,562,672**	**$ 26,933,123**	**$ (629,549)**
Hunters Point	**$ 23,670,895**	**$ 38,813,141**	**$ 24,615,715**	**$ (14,197,426)**
Hunters Point Unit 1	$ 148,754	$ 964,300	$ 780,480	
Hunters Point Unit 2	$ 1,332,556	$ 5,033,823	$ [illegible]	
Hunters Point Unit 3	$ 1,332,556	$ 5,575,139	$ [illegible]	
Hunters Point Unit 4	$ 20,857,029	$ 27,239,880	$ [illegible]	
Humboldt Bay	**$ 11,360,082**	**$ 8,763,611**	**$ 9,580,969**	**$ 817,358**
Humboldt Bay Unit 1	$ 5,696,826	$ 4,028,911	$ [illegible]	
Humboldt Bay Unit 2	$ 5,500,558	$ 4,334,740	$ [illegible]	
Mobile Gas Turbine 2	$ 64,175	$ 151,309	$ [illegible]	
Mobile Gas Turbine 3	$ 98,523	$ 248,651	$ [illegible]	

	Filed 2002 AFRR			Final CPUC Requested Analysis of 2002 AFRR**		
	O&M only	Depreciation only	Return only	O&M only	Depreciation only	Return only
Helms	$ 14,030,557	$ 147,403,717	$ 9,489,956	$ 14,030,557	$ 20,482,458	$ 67,360,007
San Joaquin Watershed	$ 8,795,208	$ 6,191,028	$ 12,576,436	$ 8,795,208	$ 5,921,138	$ 12,216,777
Hunters Point	$ 25,464,503	$ 9,372,425	$ 3,976,213	$ 10,010,869	$ 11,323,382	$ 3,281,465
Humboldt Bay	$ 4,961,266	$ 2,901,604	$ 900,741	$ 4,961,266	$ 3,735,295	$ 884,408

****Changes included in final CPUC requested analysis of 2002 AFRR:**

1 Replaced Hunters Point Units 2&3 O&M costs with previously filed settlement numbers.
2 Replaced TURN's 48-month amortization depreciation with "normal" depreciation.
3 Replaced TURN's 48-month amortization plant and reserve with "normal" plant and reserve for Helms.
4 Used "accelerated" depreciation reserve with "normal" depreciation for Hunters Point and Humboldt Bay
5 Made minor corrections to "original plant" numbers (e.g. removing all new capital additions and including all plant related capital).
6 Removed common capital allocations from all plants
7 Corrected errant decimal point in San Joaquin depreciation numbers.

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001
Annual Fixed Revenue Requirement
Helms

Schedule F, Article II Part B: Determination of Annual Revenue Requirement
Shaded cells are input values.

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The following rules and sections apply to this docur
Rule 51 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice,
Rule 408 of the Federal Rules of Evidence,
Section 1152 of the California Evidence Code

				Helms
1(A)	Annual Fixed Revenue Requirement (AFRR) is the difference between Total Annual Revenue Requirements (Section 1(C)) and Total Annual Variable Costs (Section 6(F))			$ 101,873,022
1(B)	Variable O&M Rate ($/MWh) is the ratio of Annual Variable O&M Expenses (Section 6(A)) to Annual Net Generation.			$ -
	Annual Net Generation	875,981		
1(C)	Total Annual Revenue Requirements is the sum of Operating Expenses (Section 2) and Return and Income Tax Allowance (Section 3).		$ 178,160,022	
2(A)(1)(a)	Steam Production O&M (Accounts 500-515)	$ -		
2(A)(1)(b)	Hydro Production O&M (Accounts 535-545)	$ 7,442,981		
2(A)(1)(c)	Other Power Generation O&M (Accounts 546-554)	$ 78,321		
2(A)(1)(d)	Other Power Supply Expenses (Accounts 555-557)	$ 80,759,940		
2(A)(1)	Total Production O&M Expenses	$ 88,281,242		
2(A)(2)	Transmission O&M Expenses (Accounts 560-573)	$ -		
2(A)(3)	Distribution O&M Expenses (Accounts 580-598)	$ -		
2(A)(4)	Administrative and General (Accounts 920-935)	$ 1,952,042		
2(A)	Total O&M Expenses		$ 90,233,284	
2(B)(1)	Production Plant Depreciation	$ 20,482,458		
2(B)(2)	Transmission Plant Depreciation	$ -		
2(B)(3)	Distribution Plant Depreciation	$ -		
2(B)(4)	General and Intangible Plant Depreciation	$ -		
2(B)	Depreciation Expenses (Accounts 403-407)		$ 20,482,458	
2(C)(1)	Property and Property-Related Taxes	$ 237,735		
2(C)(2)	Payroll and Labor-Related Taxes	$ -		
2(C)(3)	Other Taxes	$ -		
2(C)	Taxes other than Income Taxes (Account 408.1)		$ 237,735	
2(D)	Revenue Credits (Accounts 451, 453-456), show as negative		$ (153,462)	
2(E)	Treatment of Capital Leases		$ -	
2	Operating Expenses			$ 110,800,015
3.1	Product of Allowable Pre-Tax Rate of Return (Section 5) and Net Investment (Section 4)		$ 67,360,007	
3.2.a	t is the effective, combined state and federal income tax rate	0.00%		
3.2.b	ITC Amortization of investment tax credits (Account 411.4)	$ -		
3.2	[ITC Amortization] / (1 - t)		$ -	
3	Return and Income Tax Allowance			$ 67,360,007
4(A)(1)	Production Plant Investment (Accounts 310-316, 330-336, 340-346, 106 & 114)	$ 878,048,240		
4(A)(2)	Transmission Plant Investment (Accounts 350-359, 106 & 114)	$ -		
4(A)(3)	Distribution Plant Investment (Accounts 360-373, 106 & 114)	$ -		
4(A)(4)	General and Intangible Plant Investment (Accounts 389-399, 301-303, 106 & 114)	$ -		
4(A)	Gross Plant Investment		$ 878,048,240	
4(B)(1)	Production Plant Depreciation Reserve	$ 324,332,316		
4(B)(2)	Transmission Plant Depreciation Reserve	$ -		
4(B)(3)	Distribution Plant Depreciation Reserve	$ -		
4(B)(4)	General and Intangible Plant Reserve	$ -		
4(B)	Depreciation Reserve, show credit as positive and debit as negative		$ 324,332,316	

4(C)	CWIP, Construction Work in Progress for pollution control (Account 107)		$ -	
4(D)	PHFU, Plant Held for Future Use (Account 105)		$ -	
4(E)(1)	Production Plant ADIT	$ 5,582,321		
4(E)(2)	Transmission Plant ADIT	$ -		
4(E)(3)	Distribution Plant ADIT	$ -		
4(E)(4)	General and Intangible Plant ADIT	$ -		
4(E)	ADIT, accumulated deferred income taxes (Accounts 190, 281-283, 255), show credit as positive and debit as negative		$ 5,582,321	
4(F)(1)	Fuel Stocks (Account 151)	$ -		
4(F)(2)	Plant Materials and Supplies (Accounts 154 & 163)	$ 721		
4(F)(3)	Prepayments (Account 165)	$ -		
	Purchased Power	$ -		
	O&M Expenses (Section 2(A)) - total Annual Fuel Costs (Section 6(C)(1)) - Purchased Power	$ 13,946,284		
4(F)(4)	Working Cash Allowance is one-eighth of above amount	$ 1,743,285		
4(F)()	Unamortized Deferred Costs	$ -		
4(F)	Working Capital		$ 1,744,007	
4	Net Investment is Gross Plant Investment - Depreciation Reserve + CWIP + PHFU - ADIT + Working Capital.			$ 549,877,609
5(b)	30% of the Increase in yield on 10-year U.S. Treasury Bonds		0%	
5	Allowable Pre-Tax Rate of Return is 12.25% plus Increase in yield			12.25%
	Annual Variable O&M Expenses - Owner may choose Option 1 or Option 2			
	Select Option 1 or Option 2	1		
6(A)	Annual Variable O&M Expenses		$ -	
	Initial Variable O&M Rate	$ -		
	Annual Variable O&M Expenses - Option 1: Initial Variable O&M Rate * Net Generation (Section 1(B))		$ -	
6(A)(1)	Variable Production O&M Expenses	$ -		
6(A)(2)	Variable A&G Expenses	$ -		
	Annual Variable O&M Expenses - Option 2: Explain Classification of Expenses as fixed or variable		$ -	
6(B)(1)	Total O&M Expenses (Section 2(A))	$ 90,233,284		
6(B)(2)	Sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)), Annual Emissions Costs (Section 6(D)) and Annual Non-Fuel Start-Up Costs (Section 6(E))	$ 76,287,000		
6(B)	Annual Fixed O&M Expenses is difference between 6(B)(1) and 6(B)(2)		$ 13,946,284	
6(C)(1)	Total Annual Fuel Costs (Account 501 or 547) **	$ 76,287,000		
6(C)(2)	Annual Fixed Fuel Costs	$ -		
6(C)(3)	Annual Variable Fuel Costs		$ 76,287,000	
6(D)	Annual Emissions Costs		$ -	
6(E)	Annual Non-Fuel Start-Up Costs		$ -	
6(F)	Total Annual Variable Costs is the sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)) and Annual Emissions Costs (Section 6(D))		$ 76,287,000	

** For Helms costs, only Acount 555 has been included in 6(c)(1). This is power used for pumping, which is recovered through Schedule C.

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The following rules and sections apply to this document:
Rule 51 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice,
Rule 408 of the Federal Rules of Evidence,
Section 1152 of the California Evidence Code

Helms
Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001

July 2000 through June 2001
(in thousands of dollars)
Expense dollars from SAP, Capital dollars from Capital Accounting

Category	FERC account(s)	Total Helms including common	Helms FERC 2735 10060	Hydro Common 10187	Hydro-GEO LOB 11791	GEN Line of Bus 11688	Shared Common & General
	2002 MWh =>	875,961		13,663,067	13,663,067	14,804,615	
ANNUAL FIXED O&M EXPENSES							
Total O&M Expenses							
Steam Production O&M	500-515, less 501	0	0	0	0	0	0
Hydro Production O&M	535-545	7,443	7,031	6,202	224	0	0
Other Power Generation O&M	546-554, less 547	78	78	5	0	0	0
Other Power Supply Expenses	555-557, less 555	4,473	3,625	8	13,218	0	0
Transmission O&M Expenses	560-573	0	0	0	0	0	0
Distribution O&M Expenses	580-598	0	0	0	0	0	0
Administrative and General Expenses	920-935	1,952	1,208	1,772	9,745	97	0
Less: PX tariff administrative charges		70	70	0	0	0	0
Depreciation Expenses (see note below)	403-407	20,482	20,482	-	-	-	-
Taxes Other Than Income Taxes	408.1	238	206	412	83	0	0
Revenue Credits		0					
Less: Miscellaneous Service Revenues	451	0	0	0	0	0	0
Less: Sales of Water and Water Power	453	0	0	0	0	0	0
Less: Rent from Electric Property	454	0	0	0	0	0	0
Less: Interdepartmental Sales	455	0	0	0	0	0	0
Less: Other Electric Revenues	456	(153)	(58)	(919)	(570)	0	0
ANNUAL VARIABLE O&M EXPENSES							
Fuel Expenses							
Steam Production Fuel	501	0	0	0	0	0	0
Other Power Generation Fuel	547	0	0	0	0	0	0
Purchased Power	555	76,287	76,287	0	0	0	0
RETURN AND INCOME TAX ALLOWANCE							
Net Investment							
Gross Plant Investment	101, 102, 106, 114	879,083	879,083	0	0	0	0
Less: Depreciation Reserve	108, 111, 115	(324,332)	(324,332)	0	0	0	0
Less: Capital Additions		(1,035)	0	0	0	0	0
CWIP: for Pollution Control Projects Only	107	0	0	0	0	0	0
PHFU	105	0	0	0	0	0	0
ADIT Deferred Debits	190	278	277	13	0	16	0
Less: ADIT Deferred Credits	255, 281-283	(5,861)	(5,846)	(290)	0	61	0
Working Capital: Fuel Stocks	151	0	0	0	0	0	0
Working Capital: Plant Materials and Supplies	154, 163	1	0	8	0	4	0
Working Capital: Prepayments	165	0	0	0	0	0	0
Working Capital: Working Cash Allowance	calculated	1,735	1,484	998	2,898	12	0
Unamortized Deferred Costs	part of 186	0	0	0	0	0	0

Total contract cost equals sum of FERC license and MWh allocated shares of hydro, hydro-geothermal line of business and generation line of business costs.

Amount in Oct. 1 filing:							
Depreciation Expenses	403-407 (less Bal.Acc	147,404	147,363	507	0	134	0
Turn Accounting (48 amortizaton)							
Depreciation Expenses	403-407 (less Bal.Acc	164,971	164,712	0	0	0	259
Original "Normal" depreciation							
Depreciation Expenses	403-407 (less Bal.Acc	38,254	37,910	1,327	0	0	259
Rechecked "Normal" depreciation							
Depreciation Expenses	403-407 (less Bal.Acc	21,592	20,482	0	0	0	1,110
Amount in Oct. 1 filing:							
Gross Plant Investment	101, 102, 106, 114	876,551	874,449	4,594	0	1,246	1,734
Less: Depreciation Reserve	108, 111, 115	(795,244)	(795,113)	(1,505)	0	(580)	0
Less: Capital Additions		0	0	0	0	0	0
Turn Accounting (48 amortizaton)							
Gross Plant Investment	101, 102, 106, 114	880,014	877,640	9,983	0	0	1,734
Less: Depreciation Reserve	108, 111, 115	(796,978)	(796,624)	(5,527)	0	0	0
Less: Capital Additions		(1,035)	0	0	0	0	0
Original "Normal" plant and reserve							
Gross Plant Investment	101, 102, 106, 114	880,014	877,640	9,983	0	0	1,734
Less: Depreciation Reserve	108, 111, 115	(324,667)	(324,332)	(5,527)	0	0	0
Less: Capital Additions		(1,035)	0	0	0	0	0
Rechecked "Normal" plant and reserve							
Gross Plant Investment	101, 102, 106, 114	922,583	879,083	0	0	0	43,500
Less: Depreciation Reserve	108, 111, 115	(302,118)	(324,332)	0	0	0	22,215
Less: Capital Additions		(1,035)	0	0	0	0	0

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001
Annual Fixed Revenue Requirement
San Joaquin

Schedule F, Article II Part B: Determination of Annual Revenue Requirement
Shaded cells are input values.

				San Joaquin
1(A)	Annual Fixed Revenue Requirement (AFRR) is the difference between Total Annual Revenue Requirements (Section 1(C)) and Total Annual Variable Costs (Section 6(F))			$ 26,933,123
1(B)	Variable O&M Rate ($/MWh) is the ratio of Annual Variable O&M Expenses (Section 6(A)) to Annual Net Generation.			$ -
	Annual Net Generation	712,087		
1(C)	Total Annual Revenue Requirements is the sum of Operating Expenses (Section 2) and Return and Income Tax Allowance (Section 3).		$ 26,933,123	
2(A)(1)(a)	Steam Production O&M (Accounts 500-515)	$ -		
2(A)(1)(b)	Hydro Production O&M (Accounts 535-545)	$ 4,333,914		
2(A)(1)(c)	Other Power Generation O&M (Accounts 546-554)	$ 12,261		
2(A)(1)(d)	Other Power Supply Expenses (Accounts 555-557)	$ 1,373,308		
2(A)(1)	Total Production O&M Expenses	$ 5,719,482		
2(A)(2)	Transmission O&M Expenses (Accounts 560-573)	$ (1,000)		
2(A)(3)	Distribution O&M Expenses (Accounts 580-598)	$ -		
2(A)(4)	Administrative and General (Accounts 920-935)	$ 2,967,124		
2(A)	Total O&M Expenses		$ 8,685,606	
2(B)(1)	Production Plant Depreciation	$ 5,921,138		
2(B)(2)	Transmission Plant Depreciation	$ -		
2(B)(3)	Distribution Plant Depreciation	$ -		
2(B)(4)	General and Intangible Plant Depreciation	$ -		
2(B)	Depreciation Expenses (Accounts 403-407)		$ 5,921,138	
2(C)(1)	Property and Property-Related Taxes	$ 190,751		
2(C)(2)	Payroll and Labor-Related Taxes	$ -		
2(C)(3)	Other Taxes	$ -		
2(C)	Taxes other than Income Taxes (Account 408.1)		$ 190,751	
2(D)	Revenue Credits (Accounts 451, 453-456), show as negative		$ (81,148)	
2(E)	Treatment of Capital Leases		$ -	
2	Operating Expenses			$ 14,716,346
3.1	Product of Allowable Pre-Tax Rate of Return (Section 5) and Net Investment (Section 4)		$ 12,216,777	
3.2.a	*t* is the effective, combined state and federal income tax rate	0.00%		
3.2.b	ITC Amortization of investment tax credits (Account 411.4)	$ -		
3.2	[ITC Amortization] / (1 - *t*)		$ -	
3	Return and Income Tax Allowance			$ 12,216,777
4(A)(1)	Production Plant Investment (Accounts 310-316, 330-336, 340-346, 106 & 114)	$ 195,206,832		
4(A)(2)	Transmission Plant Investment (Accounts 350-359, 106 & 114)	$ -		
4(A)(3)	Distribution Plant Investment (Accounts 360-373, 106 & 114)	$ -		
4(A)(4)	General and Intangible Plant Investment (Accounts 389-399, 301-303, 106 & 114)	$ -		
4(A)	Gross Plant Investment		$ 195,206,832	
4(B)(1)	Production Plant Depreciation Reserve	$ 75,422,162		
4(B)(2)	Transmission Plant Depreciation Reserve	$ -		
4(B)(3)	Distribution Plant Depreciation Reserve	$ -		
4(B)(4)	General and Intangible Plant Reserve	$ -		
4(B)	Depreciation Reserve, show credit as positive and debit as negative		$ 75,422,162	

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Rule 51 of the CPUC Rules of Practice a
Rule 601 et seq. of the FERC Rules of P
Rule 408 of the Federal Rules of Eviden
Section 1152 of the California Evidence (

4(C)	CWIP, Construction Work in Progress for pollution control (Account 107)		$ -	
4(D)	PHFU, Plant Held for Future Use (Account 105)		$ -	
4(E)(1)	Production Plant ADIT	$ 21,474,500		
4(E)(2)	Transmission Plant ADIT	$ -		
4(E)(3)	Distribution Plant ADIT	$ -		
4(E)(4)	General and Intangible Plant ADIT	$ -		
4(E)	ADIT, accumulated deferred income taxes (Accounts 190, 281-283, 255), show credit as positive and debit as negative		$ 21,474,500	
4(F)(1)	Fuel Stocks (Account 151)	$ -		
4(F)(2)	Plant Materials and Supplies (Accounts 154 & 163)	$ 332,922		
4(F)(3)	Prepayments (Account 165)	$ -		
	Purchased Power	$ -		
	O&M Expenses (Section 2(A)) - total Annual Fuel Costs (Section 6(C)(1)) - Purchased Power	$ 8,685,606		
4(F)(4)	Working Cash Allowance is one-eighth of above amount	$ 1,085,701		
4(F)()	Unamortized Deferred Costs	$ -		
4(F)	Working Capital		$ 1,418,622	
4	Net Investment is Gross Plant Investment - Depreciation Reserve + CWIP + PHFU - ADIT + Working Capital.			$ 99,728,791
5(b)	30% of the Increase in yield on 10-year U.S. Treasury Bonds		0%	
5	Allowable Pre-Tax Rate of Return is 12.25% plus Increase in yield			12.25%
Annual Variable O&M Expenses - Owner may choose Option 1 or Option 2				
	Select Option 1 or Option 2	1		
6(A)	Annual Variable O&M Expenses		$ -	
	Initial Variable O&M Rate	see San Joaquin data		
	Annual Variable O&M Expenses - Option 1: Initial Variable O&M Rate * Net Generation (Section 1(B))		$ -	
6(A)(1)	Variable Production O&M Expenses	$ -		
6(A)(2)	Variable A&G Expenses	$ -		
	Annual Variable O&M Expenses - Option 2: Explain Classification of Expenses as fixed or variable		$ -	
6(B)(1)	Total O&M Expenses (Section 2(A))	$ 8,685,606		
6(B)(2)	Sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)), Annual Emissions Costs (Section 6(D)) and Annual Non-Fuel Start-Up Costs (Section 6(E))	$ -		
6(B)	Annual Fixed O&M Expenses is difference between 6(B)(1) and 6(B)(2)		$ 8,685,606	
6(C)(1)	Total Annual Fuel Costs (Account 501 or 547)	$ -		
6(C)(2)	Annual Fixed Fuel Costs	$ -		
6(C)(3)	Annual Variable Fuel Costs		$ -	
6(D)	Annual Emissions Costs		$ -	
6(E)	Annual Non-Fuel Start-Up Costs		$ -	
6(F)	Total Annual Variable Costs is the sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)) and Annual Emissions Costs (Section 6(D))		$ -	

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San Joaquin
Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001

July 2000 through June 2001
(in thousands of dollars)
Expense dollars from SAP, Capital dollars from Capital Accounting

Category	FERC account(s)	Total San Joaquin Watershed including common	Kerckhoff 1 10138	Kerckhoff 2 10139	FERC 96 Common 10140	Crane Valley 10141	San Joaquin 1A 10142	San Joaquin 2 10143	San Joaquin 3 10144	AG Wishon PH 10145	FERC 1354 Common 10146	KingsCrane Common 10192	Hydro Common 10187	Hydro-GEO LOB 11791	GEN Line of Bus 11888	Shared Common & General
	2002 MWh =>	712,087	47,126	556,089		3,507	1,791	13,057	16,423	74,114		2,238,156	13,663,067	13,663,067	14,804,615	
ANNUAL FIXED O&M EXPENSES																
Total O&M Expenses																
Steam Production O&M	500-515, less 501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Production O&M	535-545	4,334	626	708	407	384	89	299	269	304	394	1,625	6,202	224	0	0
Other Power Generation O&M	546-554, less 547	12	0	0	0	0	0	0	0	0	12	0	5	0	0	0
Other Power Supply Expenses	555-557, less 555	1,373	46	632	0	6	0	0	0	0	0	0	8	13,218	0	0
Transmission O&M Expenses	560-573	(1)	0	0	0	0	(1)	0	0	0	0	0	0	0	0	0
Distribution O&M Expenses	580-598	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative and General Expenses	920-935	2,967	186	319	7	45	14	334	30	97	1,230	315	1,772	9,745	97	0
Less: PX tariff administrative charges		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Expenses (see note below)	403-407	5,921	0	0	0	0	0	0	0	0	0	0	0	0	0	5,921
Taxes Other Than Income Taxes	408.1	191	29	18	3	16	4	20	13	16	17	91	412	83	0	0
Revenue Credits																
Less: Miscellaneous Service Revenues	451	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Sales of Water and Water Power	453	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Rent from Electric Property	454	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Interdepartmental Sales	455	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Other Electric Revenues	456	(61)	0	0	0	0	0	0	0	0	(1)	(8)	(919)	(570)	0	0
ANNUAL VARIABLE O&M EXPENSES																
Fuel Expenses																
Steam Production Fuel	501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Power Generation Fuel	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RETURN AND INCOME TAX ALLOWANCE																
Net Investment																
Gross Plant Investment	101, 102, 106, 114	198,617	5,928	159,793	5,232	10,578	1,255	2,733	3,344	5,224	4,530	0	0	0	0	0
Less: Depreciation Reserve	108, 111, 115	(75,422)	(5,385)	(56,701)	(3,060)	(4,454)	(372)	(1,105)	(1,312)	(1,713)	(1,319)	0	0	0	0	0
Less: Capital Additions		(3,410)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP: for Pollution Control Projects Only	107	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PHFU	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ADIT Deferred Debits	190	1,043	43	857	25	16	5	11	13	23	41	26	13	0	16	0
Less: ADIT Deferred Credits	255, 281-283	(22,518)	(924)	(18,512)	(542)	(353)	(108)	(232)	(287)	(487)	(887)	(552)	(290)	0	61	0
Working Capital: Fuel Stocks	151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital: Plant Materials and Supplies	154, 163	333	13	265	8	6	2	4	5	9	16	10	8	0	4	0
Working Capital: Prepayments	165	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital: Working Cash Allowance	calculated	1,086	108	207	52	54	13	79	37	50	205	243	998	2,898	12	0
Unamortized Deferred Costs	part of 186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total contract cost equals sum of powerhouse, FERC license common, and MWh allocated shares of watershed, hydro, hydro-geothermal line of business and generation line of business costs.

Category	FERC account(s)	Total San Joaquin Watershed including common	Kerckhoff 1 10138	Kerckhoff 2 10139	FERC 96 Common 10140	Crane Valley 10141	San Joaquin 1A 10142	San Joaquin 2 10143	San Joaquin 3 10144	AG Wishon PH 10145	FERC 1354 Common 10146	KingsCrane Common 10192	Hydro Common 10187	Hydro-GEO LOB 11791	GEN Line of Bus 11888	Shared Common & General
Amount in Oct. 1 filing:																
Depreciation Expenses	403-407 (less Bal.Ac	5,191	173	4,879	162	100	38	83	99	153	370	318	507	0	134	0
Turn Accounting (48 amortizaton)																
Depreciation Expenses	403-407 (less Bal.Ac	6,369	176	4,768	456	315	34	82	111	183	175	0	1,327	0	0	0
Original "Normal" depreciation																
Depreciation Expenses	403-407 (less Bal.Ac	6,369	176	4,768	456	315	34	82	111	183	175	0	1,327	0	0	0
Rechecked "Normal" depreciation																
Depreciation Expenses	403-407 (less Bal.Ac	5,921	0	0	0	0	0	0	0	0	0	0	0	0	0	5,921
Amount in Oct. 1 filing:																
Gross Plant Investment	101, 102, 106, 114	199,064	5,482	159,190	3,689	3,064	1,242	2,352	2,969	5,830	9,914	6,044	4,594	0	1,246	3,310
Less: Depreciation Reserve	108, 111, 115	(75,370)	(5,291)	(56,701)	(2,631)	(2,200)	(365)	(1,105)	(1,310)	(1,641)	(3,323)	(2,189)	(1,505)	0	(580)	0
Less: Capital Additions		(974)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turn Accounting (48 amortizaton)																
Gross Plant Investment	101, 102, 106, 114	198,648	5,812	159,190	4,482	9,003	1,254	2,352	2,973	5,223	4,530	0	9,983	0	0	3,310
Less: Depreciation Reserve	108, 111, 115	(75,710)	(5,385)	(56,701)	(3,060)	(4,454)	(372)	(1,105)	(1,312)	(1,713)	(1,319)	0	(5,527)	0	0	0
Less: Capital Additions		(3,410)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Original "Normal" plant and reserve																
Gross Plant Investment	101, 102, 106, 114	198,648	5,812	159,190	4,482	9,003	1,254	2,352	2,973	5,223	4,530	0	9,983	0	0	3,310
Less: Depreciation Reserve	108, 111, 115	(75,710)	(5,385)	(56,701)	(3,060)	(4,454)	(372)	(1,105)	(1,312)	(1,713)	(1,319)	0	(5,527)	0	0	0
Less: Capital Additions		(3,410)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rechecked "Normal" plant and reserve																
Gross Plant Investment	101, 102, 106, 114	198,617	5,928	159,793	5,232	10,578	1,255	2,733	3,344	5,224	4,530	0	0	0	0	0
Less: Depreciation Reserve	108, 111, 115	(75,422)	(5,385)	(56,701)	(3,060)	(4,454)	(372)	(1,105)	(1,312)	(1,713)	(1,319)	0	0	0	0	0
Less: Capital Additions		(3,410)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001
Annual Fixed Revenue Requirement
Hunters Pt

Schedule F, Article II Part B: Determination of Annual Revenue Requirement
Shaded cells are input values.

				Hunters Point
1(A)	Annual Fixed Revenue Requirement (AFRR) is the difference between Total Annual Revenue Requirements (Section 1(C)) and Total Annual Variable Costs (Section 6(F))			$ 24,615,715
1(B)	Variable O&M Rate ($/MWh) for Option 2 is the ratio of Annual Variable O&M Expenses (Section 6(A)) to Annual Net Generation.			$ 3.58
	Annual Net Generation	634,380		
1(C)	Total Annual Revenue Requirements is the sum of Operating Expenses (Section 2) and Return and Income Tax Allowance (Section 3).		$ 98,575,796	
2(A)(1)(a)	Steam Production O&M (Accounts 500-515)	$ 69,209,632		
2(A)(1)(b)	Hydro Production O&M (Accounts 535-545)	$ -		
2(A)(1)(c)	Other Power Generation O&M (Accounts 546-554)	$ 7,876,558		
2(A)(1)(d)	Other Power Supply Expenses (Accounts 555-557)	$ 717,634		
2(A)(1)	Total Production O&M Expenses	$ 77,803,825		
2(A)(2)	Transmission O&M Expenses (Accounts 560-573)	$ -		
2(A)(3)	Distribution O&M Expenses (Accounts 580-598)	$ -		
2(A)(4)	Administrative and General (Accounts 920-935)	$ 6,072,032		
2(A)	Total O&M Expenses		$ 83,875,857	
2(B)(1)	Production Plant Depreciation	$ 11,323,382		
2(B)(2)	Transmission Plant Depreciation	$ -		
2(B)(3)	Distribution Plant Depreciation	$ -		
2(B)(4)	General and Intangible Plant Depreciation	$ -		
2(B)	Depreciation Expenses (Accounts 403-407)		$ 11,323,382	
2(C)(1)	Property and Property-Related Taxes	$ 95,626		
2(C)(2)	Payroll and Labor-Related Taxes	$ -		
2(C)(3)	Other Taxes	$ -		
2(C)	Taxes other than Income Taxes (Account 408.1)		$ 95,626	
2(D)	Revenue Credits (Accounts 451, 453-456), show as negative		$ (534)	
2(E)	Treatment of Capital Leases		$ -	
2	Operating Expenses			$ 95,294,331
3.1	Product of Allowable Pre-Tax Rate of Return (Section 5) and Net Investment (Section 4)		$ 3,281,465	
3.2.a	*t* is the effective, combined state and federal income tax rate	0.00%		
3.2.b	ITC Amortization of investment tax credits (Account 411.4)	$ -		
3.2	[ITC Amortization] / (1 - *t*)		$ -	
3	Return and Income Tax Allowance			$ 3,281,465
4(A)(1)	Production Plant Investment (Accounts 310-316, 330-336, 340-346, 106 & 114)	$ 130,379,129		
4(A)(2)	Transmission Plant Investment (Accounts 350-359, 106 & 114)	$ -		
4(A)(3)	Distribution Plant Investment (Accounts 360-373, 106 & 114)	$ -		
4(A)(4)	General and Intangible Plant Investment (Accounts 389-399, 301-303, 106 & 114)	$ -		
4(A)	Gross Plant Investment		$ 130,379,129	
4(B)(1)	Production Plant Depreciation Reserve	$ 114,494,327		
4(B)(2)	Transmission Plant Depreciation Reserve	$ -		
4(B)(3)	Distribution Plant Depreciation Reserve	$ -		
4(B)(4)	General and Intangible Plant Reserve	$ -		
4(B)	Depreciation Reserve, show credit as positive and debit as negative		$ 114,494,327	

FOR SETTLEMENT PURPOSES ONLY
The following rules and sections app
Rule 51 of the CPUC Rules of Practice
Rule 601 et seq. of the FERC Rules of
Rule 408 of the Federal Rules of Eviden
Section 1152 of the California Evidence

4(C)	CWIP, Construction Work in Progress for pollution control (Account 107)		$ -	
4(D)	PHFU, Plant Held for Future Use (Account 105)		$ -	
4(E)(1)	Production Plant ADIT	$ (8,278,395)		
4(E)(2)	Transmission Plant ADIT	$ -		
4(E)(3)	Distribution Plant ADIT	$ -		
4(E)(4)	General and Intangible Plant ADIT	$ -		
4(E)	ADIT, accumulated deferred income taxes (Accounts 190, 281-283, 255), show credit as positive and debit as negative		$ (8,278,395)	
4(F)(1)	Fuel Stocks (Account 151)	$ 858,859		
4(F)(2)	Plant Materials and Supplies (Accounts 154 & 163)	$ 442,053		
4(F)(3)	Prepayments (Account 165)	$ -		
	Purchased Power	$ -		
	O&M Expenses (Section 2(A)) - total Annual Fuel Costs (Section 6(C)(1)) - Purchased Power	$ 12,186,857		
4(F)(4)	Working Cash Allowance is one-eighth of above amount	$ 1,523,357		
4(F)()	Unamortized Deferred Costs	$ -		
4(F)	Working Capital		$ 2,624,269	
4	Net Investment is Gross Plant Investment - Depreciation Reserve + CWIP + PHFU - ADIT + Working Capital.			$ 26,787,466
5(b)	30% of the Increase in yield on 10-year U.S. Treasury Bonds		0%	
5	Allowable Pre-Tax Rate of Return is 12.25% plus increase in yield			12.25%
	Annual Variable O&M Expenses - Owner may choose Option 1 or Option 2			
	Select Option 1 or Option 2	1		
6(A)	Annual Variable O&M Expenses		$ 2,271,080	
	Initial Variable O&M Rate	see "HP data"		$/MWh 3.58
	Annual Variable O&M Expenses - Option 1: Initial Variable O&M Rate * Net Generation (Section 1(B))		$ 2,271,080	MWh 634,380
6(A)(1)	Variable Production O&M Expenses	$ -		
6(A)(2)	Variable A&G Expenses	$ -		
	Annual Variable O&M Expenses - Option 2: Explain Classification of Expenses as fixed or variable		$ -	
6(B)(1)	Total O&M Expenses (Section 2(A))	$ 83,875,857		
6(B)(2)	Sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)), Annual Emissions Costs (Section 6(D)) and Annual Non-Fuel Start-Up Costs (Section 6(E))	$ 73,960,080		
6(B)	Annual Fixed O&M Expenses is difference between 6(B)(1) and 6(B)(2)		$ 9,915,777	
6(C)(1)	Total Annual Fuel Costs (Account 501 or 547)	$ 71,689,000		
6(C)(2)	Annual Fixed Fuel Costs	$ -		
6(C)(3)	Annual Variable Fuel Costs		$ 71,689,000	
6(D)	Annual Emissions Costs		$ -	
6(E)	Annual Non-Fuel Start-Up Costs		$ -	
6(F)	Total Annual Variable Costs is the sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)) and Annual Emissions Costs (Section 6(D))		$ 73,960,080	

FOR SETTLEMENT PURPOSES ONLY
The following rules and sections apply to this document:
Rule 51 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice,
Rule 408 of the Federal Rules of Evidence,
Section 1152 of the California Evidence Code
July 2000 through June 2001
(in thousands of dollars)
Expense dollars from SAP, Capital dollars from Capital Accounting

Hunters Point
Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001

	2002 MWh =>	was [illegible] MWh [illegible]	20,837	[illegible]	588,611		1,141,548	1,141,548	14,804,615		was [illegible] MW
	Cost Year MWh =>		64,227		634,380						
	Initial O&M $/MWh =>		$0.00	[illegible] (see note to side)	$3.58						was [illegible]
Category	**FERC account(s)**	**Total Hunters Point including common**	**HP Jet 10017**	[illegible]	**Hunters Pt 4 10023**	**Hunters Pt Common 10024**	**Fossil Common 11532**	**Non-Div Fossil LOB 11792**	**GEN Line of Bus 11688**	**Shared Common & General**	[illegible]
ANNUAL FIXED O&M EXPENSES											
Total O&M Expenses											
Steam Production O&M	500-515, less 501	4,448	0	[illegible]	2,313	169	1,037	0	0	0	[illegible]
Hydro Production O&M	535-545	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Other Power Generation O&M	546-554, less 547	950	403	[illegible]	522	0	46	0	0	0	[illegible]
Other Power Supply Expenses	555-557, less 555	718	0	[illegible]	684	0	63	0	0	0	[illegible]
Transmission O&M Expenses	560-573	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Distribution O&M Expenses	580-598	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Administrative and General Expenses	920-935	6,073	25	[illegible]	3,706	172	87	2,306	97	0	[illegible]
Less: PX tariff administrative charges		0	0	[illegible]	0	0	0	0	0	0	[illegible]
Less: portion of Hunters Pt Unit 4 repair in '00 reimbursed by ISO		532	0	[illegible]	532	0	0	0	0	0	[illegible]
Depreciation Expenses (see note below)	403-407	11,323	0	[illegible]	0	11,323	0	0	0	0	[illegible]
Taxes Other Than Income Taxes	408.1	96	13	[illegible]	27	18	37	11	0	0	[illegible]
Revenue Credits											
Less: Miscellaneous Service Revenues	451	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Less: Sales of Water and Water Power	453	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Less: Rent from Electric Property	454	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Less: Interdepartmental Sales	455	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Less: Other Electric Revenues	456	(1)	0	[illegible]	0	0	(1)	0	0	0	[illegible]
ANNUAL VARIABLE O&M EXPENSES											
Fuel Expenses											
Steam Production Fuel	501	64,762	(104)	[illegible]	15,037	49,829	0	0	0	0	[illegible]
Other Power Generation Fuel	547	6,927	2,761	[illegible]	(524)	4,690	0	0	0	0	[illegible]
Purchased Power	555	0	0	[illegible]	0	0	0	0	0	0	[illegible]
RETURN AND INCOME TAX ALLOWANCE											
Net Investment											
Gross Plant Investment	101, 102, 106, 114	134,735	0	[illegible]	0	131,755	0	0	0	2,980	[illegible]
Less: Depreciation Reserve	108, 111, 115	(114,494)	0	[illegible]	0	(114,494)	0	0	0	0	[illegible]
Less: Capital Additions		(4,356)	0	[illegible]	0	0	0	0	0	0	[illegible]
CWIP: for Pollution Control Projects Only	107	0	0	[illegible]	0	0	0	0	0	0	[illegible]
PHFU	105	0	0	[illegible]	0	0	0	0	0	0	[illegible]
ADIT Deferred Debits	190	1,728	257	[illegible]	191	1,279	0	0	16	0	[illegible]
Less: ADIT Deferred Credits	255, 281-283	6,550	985	[illegible]	730	4,892	0	0	61	0	[illegible]
Working Capital: Fuel Stocks	151	659	659	[illegible]	0	0	0	0	0	0	[illegible]
Working Capital: Plant Materials and Supplies	154, 163	442	66	[illegible]	49	327	0	0	4	0	[illegible]
Working Capital: Prepayments	165	0	0	[illegible]	0	0	0	0	0	0	[illegible]
Working Capital: Working Cash Allowance	calculated	1,457	54	[illegible]	837	43	154	288	12	0	[illegible]
Unamortized Deferred Costs	part of 186	0	0	[illegible]	0	0	0	0	0	0	[illegible]

Total facility cost equals sum of unit, facility common, and MWh allocated shares of fossil common, non-div fossil line of business and generation line of business costs.

Amount in Oct. 1 filing:											
Depreciation Expenses	403-407 (less Bal.A	9,370	824	1,420	1,376	5,745	0	0	134	0	[illegible]
Turn Accounting (48 amortizaton)											
Depreciation Expenses	403-407 (less Bal.A	8,940	0	0	0	8,497	0	0	0	443	[illegible]
Original "Normal" depreciation											
Depreciation Expenses	403-407 (less Bal.A	12,026	0	0	0	11,283	561	0	0	443	[illegible]
Rechecked "Normal" depreciation											
Depreciation Expenses	403-407 (less Bal.A	11,323	0	0	0	11,323	0	0	0	0	[illegible]
Amount in Oct. 1 filing:											
Gross Plant Investment	101, 102, 106, 114	130,972	17,491	17,952	16,321	76,177	0	0	1,246	2,980	[illegible]
Less: Depreciation Reserve	108, 111, 115	(111,956)	(16,569)	(12,046)	(7,727)	(75,591)	0	0	(580)	0	[illegible]
Less: Capital Additions		(586)	0	0	0	0	0	0	0	0	[illegible]
Turn Accounting (48 amortizaton)											
Gross Plant Investment	101, 102, 106, 114	134,735	0	0	0	131,755	0	0	0	2,980	[illegible]
Less: Depreciation Reserve	108, 111, 115	(114,494)	0	0	0	(114,494)	0	0	0	0	[illegible]
Less: Capital Additions		(4,356)	0	0	0	0	0	0	0	0	[illegible]
Original "Normal" plant and reserve											
Gross Plant Investment	101, 102, 106, 114	136,232	0	0	0	131,755	2,803	0	0	2,980	[illegible]
Less: Depreciation Reserve	108, 111, 115	(101,645)	0	0	0	(100,654)	(1,857)	0	0	0	[illegible]
Less: Capital Additions		(4,356)	0	0	0		0	0	0	0	[illegible]
Rechecked "Normal" plant and reserve											
Gross Plant Investment	101, 102, 106, 114	131,755	0	0	0	131,755	0	0	0	0	[illegible]
Less: Depreciation Reserve	108, 111, 115	(100,654)	0	0	0	(100,654)	0	0	0	0	[illegible]
Less: Capital Additions		(4,356)	0	0	0	0	0	0	0	0	[illegible]

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001
Annual Fixed Revenue Requirement
Humboldt

Schedule F, Article II Part B: Determination of Annual Revenue Requirement
Shaded cells are input values.

				Humboldt Bay
1(A)	Annual Fixed Revenue Requirement (AFRR) is the difference between Total Annual Revenue Requirements (Section 1(C)) and Total Annual Variable Costs (Section 6(F))			$ 9,580,968
1(B)	Variable O&M Rate ($/MWh) for option 2 is the ratio of Annual Variable O&M Expenses (Section 6(A)) to Annual Net Generation.			$ 5.90
	Annual Net Generation	702,220		
1(C)	Total Annual Revenue Requirements is the sum of Operating Expenses (Section 2) and Return and Income Tax Allowance (Section 3).		$ 83,239,066	
			FOR SETTLEMENT PURPOSES ONL	
2(A)(1)(a)	Steam Production O&M (Accounts 500-515)	$ 71,286,120	**The following rules and sections ap**	
2(A)(1)(b)	Hydro Production O&M (Accounts 535-545)	$ -	Rule 51 of the CPUC Rules of Practice	
2(A)(1)(c)	Other Power Generation O&M (Accounts 546-554)	$ 4,541,204	Rule 601 et seq. of the FERC Rules of	
2(A)(1)(d)	Other Power Supply Expenses (Accounts 555-557)	$ 893,714	Rule 408 of the Federal Rules of Evide	
2(A)(1)	Total Production O&M Expenses	$ 76,721,038	Section 1152 of the California Evidenc	
2(A)(2)	Transmission O&M Expenses (Accounts 560-573)	$ -		
2(A)(3)	Distribution O&M Expenses (Accounts 580-598)	$ -		
2(A)(4)	Administrative and General (Accounts 920-935)	$ 1,529,856		
2(A)	Total O&M Expenses		$ 78,250,894	
2(B)(1)	Production Plant Depreciation	$ 3,735,295		
2(B)(2)	Transmission Plant Depreciation	$ -		
2(B)(3)	Distribution Plant Depreciation	$ -		
2(B)(4)	General and Intangible Plant Depreciation	$ -		
2(B)	Depreciation Expenses (Accounts 403-407)		$ 3,735,295	
2(C)(1)	Property and Property-Related Taxes	$ 369,735		
2(C)(2)	Payroll and Labor-Related Taxes	$ -		
2(C)(3)	Other Taxes	$ -		
2(C)	Taxes other than Income Taxes (Account 408.1)		$ 369,735	
2(D)	Revenue Credits (Accounts 451, 453-456), show as negative		$ (1,265)	
2(E)	Treatment of Capital Leases		$ -	
2	Operating Expenses			$ 82,354,658
3.1	Product of Allowable Pre-Tax Rate of Return (Section 5) and Net Investment (Section 4)		$ 884,408	
3.2.a	*t* is the effective, combined state and federal income tax rate	0.00%		
3.2.b	ITC Amortization of investment tax credits (Account 411.4)	$ -		
3.2	[ITC Amortization] / (1 - *t*)		$ -	
3	Return and Income Tax Allowance			$ 884,408
4(A)(1)	Production Plant Investment (Accounts 310-316, 330-336, 340-346, 106 & 114)	$ 40,060,283		
4(A)(2)	Transmission Plant Investment (Accounts 350-359, 106 & 114)	$ -		
4(A)(3)	Distribution Plant Investment (Accounts 360-373, 106 & 114)	$ -		
4(A)(4)	General and Intangible Plant Investment (Accounts 389-399, 301-303, 106 & 114)	$ -		
4(A)	Gross Plant Investment		$ 40,060,283	
4(B)(1)	Production Plant Depreciation Reserve	$ 37,384,383		
4(B)(2)	Transmission Plant Depreciation Reserve	$ -		
4(B)(3)	Distribution Plant Depreciation Reserve	$ -		
4(B)(4)	General and Intangible Plant Reserve	$ -		
4(B)	Depreciation Reserve, show credit as positive and debit as negative		$ 37,384,383	

Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001
Annual Fixed Revenue Requirement
Humboldt

4(C)	CWIP, Construction Work in Progress for pollution control (Account 107)		$ -	
4(D)	PHFU, Plant Held for Future Use (Account 105)		$ -	
4(E)(1)	Production Plant ADIT	$ (3,113,179)		
4(E)(2)	Transmission Plant ADIT	$ -		
4(E)(3)	Distribution Plant ADIT	$ -		
4(E)(4)	General and Intangible Plant ADIT	$ -		
4(E)	ADIT, accumulated deferred income taxes (Accounts 190, 281-283, 255), show credit as positive and debit as negative		$ (3,113,179)	
4(F)(1)	Fuel Stocks (Account 151)	$ 173,518		
4(F)(2)	Plant Materials and Supplies (Accounts 154 & 163)	$ 165,075		
4(F)(3)	Prepayments (Account 165)	$ -		
	Purchased Power	$ -		
	O&M Expenses (Section 2(A)) - total Annual Fuel Costs (Section 6(C)(1)) - Purchased Power	$ 8,735,894		
4(F)(4)	Working Cash Allowance is one-eighth of above amount	$ 1,091,987		
4(F)()	Unamortized Deferred Costs	$ -		
4(F)	Working Capital		$ 1,430,580	
4	Net Investment is Gross Plant Investment - Depreciation Reserve + CWIP + PHFU - ADIT + Working Capital.			$ 7,219,659
5(b)	30% of the increase in yield on 10-year U.S. Treasury Bonds		0%	
5	Allowable Pre-Tax Rate of Return is 12.25% plus increase in yield			12.25%

Annual Variable O&M Expenses - Owner may choose Option 1 or Option 2

	Select Option 1 or Option 2	2		
6(A)	Annual Variable O&M Expenses		$ 4,143,098	
	Initial Variable O&M Rate	see "HB data"		
	Annual Variable O&M Expenses - Option 1: Initial Variable O&M Rate * Net Generation (Section 1(B))		$ 21,832,020	
				$/MWh
6(A)(1)	Variable Production O&M Expenses	$ 4,143,098		$ 5.90
6(A)(2)	Variable A&G Expenses	$ -		MWh
	Annual Variable O&M Expenses - Option 2: Explain Classification of Expenses as fixed or variable		$ 4,143,098	702,220
6(B)(1)	Total O&M Expenses (Section 2(A))	$ 78,250,894		
6(B)(2)	Sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)), Annual Emissions Costs (Section 6(D)) and Annual Non-Fuel Start-Up Costs (Section 6(E))	$ 73,658,098		
6(B)	Annual Fixed O&M Expenses is difference between 6(B)(1) and 6(B)(2)		$ 4,592,796	
6(C)(1)	Total Annual Fuel Costs (Account 501 or 547)	$ 69,515,000		
6(C)(2)	Annual Fixed Fuel Costs	$ -		
6(C)(3)	Annual Variable Fuel Costs		$ 69,515,000	
6(D)	Annual Emissions Costs		$ -	
6(E)	Annual Non-Fuel Start-Up Costs		$ -	
6(F)	Total Annual Variable Costs is the sum of Annual Variable O&M Expenses (Section 6(A)), Annual Variable Fuel Costs (Section 6(C)(3)) and Annual Emissions Costs (Section 6(D))		$ 73,658,098	

FOR SETTLEMENT PURPOSES ONLY
The following rules and sections apply to this document:
Rule 51 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice,
Rule 408 of the Federal Rules of Evidence,
Section 1152 of the California Evidence Code

July 2000 through June 2001
(in thousands of dollars)
Expense dollars from SAP, Capital dollars from Capital Accounting

Humboldt Bay
Pacific Gas and Electric Company
Schedule F Informational Filing, October 1, 2001

Category	FERC account(s)	Humboldt Bay including common	Humboldt Bay 1 10025	Humboldt Bay 2 10026	Mobile Gas Tur 2 10028	Mobile Gas Tur 3 10029	Humboldt Bay Common 10027	Fossil Common 11532	Non-Div Fossil LOB 11792	GEN Line of Bus 11688	Shared Common & General
	2002 MWh =>	302,857	139,233	149,802	5,229	8,593		1,141,548	1,141,548	14,804,615	
	Cost Year MWh =>		321,237	380,983	13,766	23,703					
	Initial O&M $/MWh =>		$31.09	$31.09	$0.00	$0.00					
ANNUAL FIXED O&M EXPENSES											
Total O&M Expenses											
Steam Production O&M	500-515, less 501	6,219	1,335	594	145	125	3,745	1,037	0	0	0
Hydro Production O&M	535-545	0	0	0	0	0	0	0	0	0	0
Other Power Generation O&M	546-554, less 547	93	0	0	76	5	0	46	0	0	0
Other Power Supply Expenses	555-557, less 555	894	239	121	517	0	0	63	0	0	0
Transmission O&M Expenses	560-573	0	0	0	0	0	0	0	0	0	0
Distribution O&M Expenses	580-598	0	0	0	0	0	0	0	0	0	0
Administrative and General Expenses	920-935	1,530	127	88	65	43	570	87	2,306	97	0
Less: PX tariff administrative charges		0	0	0	0	0	0	0	0	0	0
Depreciation Expenses (see note below)	403-407	3,735	0	0	0	0	3,735	0	0	0	0
Taxes Other Than Income Taxes	408.1	370	56	35	2	5	259	37	11	0	0
Revenue Credits											
Less: Miscellaneous Service Revenues	451	0	0	0	0	0	0	0	0	0	0
Less: Sales of Water and Water Power	453	0	0	0	0	0	0	0	0	0	0
Less: Rent from Electric Property	454	(1)	0	0	0	0	(1)	0	0	0	0
Less: Interdepartmental Sales	455	0	0	0	0	0	0	0	0	0	0
Less: Other Electric Revenues	456	(0)	0	0	0	0	0	(1)	0	0	0
ANNUAL VARIABLE O&M EXPENSES											
Fuel Expenses											
Steam Production Fuel	501	65,067	0	0	0	0	65,067	0	0	0	0
Other Power Generation Fuel	547	4,448	0	0	0	0	4,448	0	0	0	0
Purchased Power	555	0	0	0	0	0	0	0	0	0	0
RETURN AND INCOME TAX ALLOWANCE											
Net Investment											
Gross Plant Investment	101, 102, 106, 114	40,210	0	0	0	0	39,579	0	0	0	631
Less: Depreciation Reserve	108, 111, 115	(37,384)	0	0	0	0	(37,384)	0	0	0	0
Less: Capital Additions		(150)	0	0	0	0	0	0	0	0	0
CWIP: for Pollution Control Projects Only	107	0	0	0	0	0	0	0	0	0	0
PHFU	105	0	0	0	0	0	0	0	0	0	0
ADIT Deferred Debits	190	645	2	4	26	26	586	0	0	16	0
Less: ADIT Deferred Credits	255, 281-283	2,468	6	17	101	99	2,243	0	0	61	0
Working Capital: Fuel Stocks	151	174	0	0	0	0	174	0	0	0	0
Working Capital: Plant Materials and Supplies	154, 163	165	0	1	7	7	150	0	0	4	0
Working Capital: Prepayments	165	0	0	0	0	0	0	0	0	0	0
Working Capital: Working Cash Allowance	calculated	1,092	213	100	100	22	539	154	288	12	0
Unamortized Deferred Costs	part of 186	0	0	0	0	0	0	0	0	0	0

Total facility cost equals sum of unit, facility common, and MWh allocated shares of fossil common, non-div fossil line of business and generation line of business costs.

Category	FERC account(s)	Humboldt Bay including common	Humboldt Bay 1 10025	Humboldt Bay 2 10026	Mobile Gas Tur 2 10028	Mobile Gas Tur 3 10029	Humboldt Bay Common 10027	Fossil Common 11532	Non-Div Fossil LOB 11792	GEN Line of Bus 11688	Shared Common & General
Amount in Oct. 1 filing:											
Depreciation Expenses	403-407 (less Bal.Ac	2,902	22	40	57	40	2,740	0	0	134	0
Turn Accounting (48 amortizaton)											
Depreciation Expenses	403-407 (less Bal.Ac	2,239	0	0	0	0	2,145	0	0	0	94
Original "Normal" depreciation											
Depreciation Expenses	403-407 (less Bal.Ac	3,977	0	0	0	0	3,734	561	0	0	94
Rechecked "Normal" depreciation											
Depreciation Expenses	403-407 (less Bal.Ac	3,735	0	0	0	0	3,735	0	0	0	0
Amount in Oct. 1 filing:											
Gross Plant Investment	101, 102, 106, 114	40,236	155	437	1,715	1,650	35,622	0	0	1,246	631
Less: Depreciation Reserve	108, 111, 115	(37,396)	(42)	(85)	(1,344)	(1,345)	(34,568)	0	0	(580)	0
Less: Capital Additions		(30)	0	0	0	0	0	0	0	0	0
Turn Accounting (48 amortizaton)											
Gross Plant Investment	101, 102, 106, 114	40,210	0	0	0	0	39,579	0	0	0	631
Less: Depreciation Reserve	108, 111, 115	(37,384)	0	0	0	0	(37,384)	0	0	0	0
Less: Capital Additions		(150)	0	0	0	0	0	0	0	0	0
Original "Normal" plant and reserve											
Gross Plant Investment	101, 102, 106, 114	40,954	0	0	0	0	39,579	2,803	0	0	631
Less: Depreciation Reserve	108, 111, 115	(35,295)	0	0	0	0	(34,803)	(1,857)	0	0	0
Less: Capital Additions		(150)	0	0	0	0	0	0	0	0	0
Rechecked "Normal" plant and reserve											
Gross Plant Investment	101, 102, 106, 114	39,579	0	0	0	0	39,579	0	0	0	0
Less: Depreciation Reserve	108, 111, 115	(34,803)	0	0	0	0	(34,803)	0	0	0	0
Less: Capital Additions		(150)	0	0	0	0	0	0	0	0	0

EXHIBIT B

Helms Pumped Storage
PG&E Rate Schedule First Revised No. 207
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS
Redlines

Where:

- Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

- For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
All	0.50

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

	Condition 1	Condition 2
All	~~$13,421.10~~$7,999.15	N/A[1]

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

[1] Hydroelectric Facilities are not permitted to elect Condition 2.

- For Units under Condition 1, the Surcharge Payment Factor for all Capital Items covered by the Small Project Budget shall be the Fixed Option Payment Factor. For all other Capital Items, the Surcharge Payment Factor shall be as agreed to by Owner and ISO. If the Owner and ISO do not agree on the Surcharge Payment Factor, the Surcharge Payment Factor shall equal the Fixed Option Payment Factor, unless the Owner demonstrates in ADR that it would not have installed the proposed Capital Item in accordance with Good Industry Practice but for its obligations to the ISO under this Agreement, in which case the Surcharge Payment Factor shall be as determined in ADR.
- For Units under Condition 2, the Surcharge Payment Factor is 1.

The Hourly Capital Item Charges for the Contract Year are set forth in Table B-2 below:

Table B-2

Unit	Capital Item Project No.	Annual Capital Item Cost	Condition 1 Surcharge Payment Factor	Condition 1 Hourly Capital Item Charge	Condition 2 Hourly Capital Item Charge

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

5. The Monthly Nonperformance Penalty is calculated pursuant to Section 8.5 using the following variables:

A. Hourly Penalty Rate

A Unit's Hourly Penalty Rate for each Contract Year is the lesser of (a) the Unit's Hourly Availability Rate for the Contract Year (calculated pursuant to Item 2.A above), or (b) three times the Unit's Hourly Availability Charge for the Contract Year (as shown in Table B-1 above).

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

	Condition 1	Condition 2
All	~~$26,842.20~~$15,998.29	N/A

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
All	1,264	1,128	6,368

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
All	~~$170,924,230~~$101,873,022

8. Limited Section 205 Filing for an Extension of Contract Term

If ISO has extended the term of this Agreement pursuant to Section 2.1(b), then not later than October 31 of the expiring Contract Year, Owner shall make a filing with FERC under Section 205 of the Federal Power Act containing the values in Tables B-1 through B-6 for the ensuing Contract Year.

In the event that a Long-term Planned Outage that is scheduled for the last quarter of the expiring Contract Year is postponed or rescheduled after October 31 of such year to the ensuing Contract Year, Owner shall make an additional Section 205 filing to revise the values in Tables B-1 through B-5 to reflect such rescheduled Long-term Planned Outage Hours.

Helms Pumped Storage
PG&E Rate Schedule First Revised No. 207
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS
Clean Version

Where:

- Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

- For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
All	0.50

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

	Condition 1	Condition 2
All	$7,999.15	N/A[1]

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

[1] Hydroelectric Facilities are not permitted to elect Condition 2.

- For Units under Condition 1, the Surcharge Payment Factor for all Capital Items covered by the Small Project Budget shall be the Fixed Option Payment Factor. For all other Capital Items, the Surcharge Payment Factor shall be as agreed to by Owner and ISO. If the Owner and ISO do not agree on the Surcharge Payment Factor, the Surcharge Payment Factor shall equal the Fixed Option Payment Factor, unless the Owner demonstrates in ADR that it would not have installed the proposed Capital Item in accordance with Good Industry Practice but for its obligations to the ISO under this Agreement, in which case the Surcharge Payment Factor shall be as determined in ADR.

- For Units under Condition 2, the Surcharge Payment Factor is 1.

The Hourly Capital Item Charges for the Contract Year are set forth in Table B-2 below:

Table B-2

Unit	Capital Item Project No.	Annual Capital Item Cost	Condition 1 Surcharge Payment Factor	Condition 1 Hourly Capital Item Charge	Condition 2 Hourly Capital Item Charge

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

5. The Monthly Nonperformance Penalty is calculated pursuant to Section 8.5 using the following variables:

A. Hourly Penalty Rate

A Unit's Hourly Penalty Rate for each Contract Year is the lesser of (a) the Unit's Hourly Availability Rate for the Contract Year (calculated pursuant to Item 2.A above), or (b) three times the Unit's Hourly Availability Charge for the Contract Year (as shown in Table B-1 above).

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

	Condition 1	Condition 2
All	$15,998.29	N/A

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
All	1,264	1,128	6,368

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
All	$101,873,022

8. Limited Section 205 Filing for an Extension of Contract Term

If ISO has extended the term of this Agreement pursuant to Section 2.1(b), then not later than October 31 of the expiring Contract Year, Owner shall make a filing with FERC under Section 205 of the Federal Power Act containing the values in Tables B-1 through B-6 for the ensuing Contract Year.

In the event that a Long-term Planned Outage that is scheduled for the last quarter of the expiring Contract Year is postponed or rescheduled after October 31 of such year to the ensuing Contract Year, Owner shall make an additional Section 205 filing to revise the values in Tables B-1 through B-5 to reflect such rescheduled Long-term Planned Outage Hours.

Humboldt Bay Power Plant
PG&E Rate Schedule FERC No. 208
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS

Redlines

12. Contract Service Limits

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups
1	139,233	7,590	5
2	149,802	7,550	7
Mob. 2	5,229	457	84
Mob. 3	8,593	697	139

Maximum Monthly MWh (Hydroelectric Units only) (N/A)

MWh

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

13. Owner's Repair Cost Obligation

Owner's Repair Cost Obligation for the current Contract Year is ~~$1,584,167~~ $137,784. ~~Note that this is the combined deductible for the Humboldt and Hunters Point Facilities.~~

14. Existing Contractual Limitations and Other Contract Restrictions on Market Transactions

None.

15. Applicable UDC Tariff(s)

PG&E's Schedule S-Standby Service will apply for the provision of auxiliary power wherever the UDC tariff is used for the cost of auxiliary power in these Schedules.

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

$ For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
1	0.50
2	0.50
Mob. 2	0.50
Mob. 3	0.50

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

Unit	Condition 1	Condition 2
1	~~$258.04~~ $282.11	~~$516.09~~ $564.22
2	~~$274.06~~ $299.62	~~$548.12~~ $599.24
Mob. 2	~~$9.78~~$10.69	~~$19.56~~ $21.39
Mob. 3	~~$16.58~~ $18.13	~~$33.16~~ $36.25

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

Unit	Condition 1	Condition 2
1	~~$516.09~~ $564.22	~~$516.09~~ $564.22
2	~~$548.12~~ $599.24	~~$548.12~~ $599.24
Mob. 2	~~$19.56~~ $21.39	~~$19.56~~ $21.39
Mob. 3	~~$33.16~~ $36.25	~~$33.16~~ $36.25

B. Hourly Surcharge Penalty Rate

A Unit's Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate

6. Target Available Hours

A Unit's Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

$$\text{Target Available Hours (TAH)} = \begin{pmatrix}\text{Hours in the}\\ \text{Calendar Year}\end{pmatrix} - \left[\begin{pmatrix}\text{Average Other}\\ \text{Outage Hours}\end{pmatrix} + \begin{pmatrix}\text{Long - Term Planned}\\ \text{Outage Hours}\end{pmatrix}\right]$$

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
1	425	528	7, 807
2	3 24	528	7,908
Mob. 2	522	504	7,734
Mob. 3	758	504	7,498

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
1	~~$4,028,911~~ $4,404,676
2	~~$4,334,740~~ $4,739,029
Mob. 2	~~$151,309~~ $165,421
Mob. 3	~~$248,651~~ $271,842

Humboldt Bay Power Plant
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SETTLEMENT SUBSTITUTE REVISED SHEETS

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12. Contract Service Limits

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups
1	139,233	7,590	5
2	149,802	7,550	7
Mob. 2	5,229	457	84
Mob. 3	8,593	697	139

Maximum Monthly MWh (Hydroelectric Units only) (N/A)

MWh

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

13. Owner's Repair Cost Obligation

Owner's Repair Cost Obligation for the current Contract Year is $137,784.

14. Existing Contractual Limitations and Other Contract Restrictions on Market Transactions

None.

15. Applicable UDC Tariff(s)

PG&E's Schedule S-Standby Service will apply for the provision of auxiliary power wherever the UDC tariff is used for the cost of auxiliary power in these Schedules.

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

$ For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
1	0.50
2	0.50
Mob. 2	0.50
Mob. 3	0.50

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

Unit	Condition 1	Condition 2
1	$282.11	$564.22
2	$299.62	$599.24
Mob. 2	$10.69	$21.39
Mob. 3	$18.13	$36.25

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

Unit	Condition 1	Condition 2
1	$564.22	$564.22
2	$599.24	$599.24
Mob. 2	$21.39	$21.39
Mob. 3	$36.25	$36.25

B. Hourly Surcharge Penalty Rate

A Unit's Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate

6. Target Available Hours

A Unit's Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

$$\text{Target Available Hours (TAH)} = \begin{pmatrix}\text{Hours in the}\\ \text{Calendar Year}\end{pmatrix} - \left[\begin{pmatrix}\text{Average Other}\\ \text{Outage Hours}\end{pmatrix} + \begin{pmatrix}\text{Long - Term Planned}\\ \text{Outage Hours}\end{pmatrix}\right]$$

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
1	425	528	7, 807
2	3 24	528	7,908
Mob. 2	522	504	7,734
Mob. 3	758	504	7,498

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
1	$4,404,676
2	$4,739,029
Mob. 2	$165,421
Mob. 3	$271,842

Hunters Point Power Plant
PG&E Rate Schedule FERC No. 209
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS

Redlines

12. Contract Service Limits

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups
1	20,837	851	68
2	N/A	~~4,847~~ 7,446	19
3	N/A	~~5,311~~ 7,446	24
4	588,611	6,545	11

Maximum Monthly MWh (Hydroelectric Units only) (N/A)

MWh

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

13. Owner's Repair Cost Obligation

Owner's Repair Cost Obligation for the current Contract Year is ~~$1,584,167~~$297,473. ~~Note that this is the combined deductible for the Hunters Point and Humboldt Facilities.~~

14. Existing Contractual Limitations and Other Contract Restrictions on Market Transactions

The only restriction that applies is the agreement between PG&E and the City and County of San Francisco:

In the "Agreement between the City and County of San Francisco and Pacific Gas and Electric Company to Close the Hunters Point Power Plant," signed July 9, 1998, PG&E agreed to permanently switch to the then-existing Conditions of Must-Run Agreement "C" or its substantively equivalent successor contract. Under this Must-Run Service Agreement, Condition 2 is the successor to Condition C. Pursuant to this commitment, PG&E agreed to operate the Hunters Point Power Plant only when called upon to do so by the ISO for reliability purposes.

15. Applicable UDC Tariff(s)

PG&E's Schedule S-Standby Service will apply for the provision of auxiliary power wherever the UDC Tariff is used for the cost of auxiliary power in these Schedules.

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

$ For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
	N/A

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

Unit	Condition 1	Condition 2
1	N/A[1]	~~$118.15~~ $91.95
2	N/A	~~$1,142.88~~ $178.96
3	N/A	~~$1,169.78~~ $178.96
4	N/A	~~$5,718.60~~ $4,450.64

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

[1] Hunters Point is restricted to operating as a Condition 2 Facility per the agreement between PG&E and the City and County of San Francisco noted in Schedule A, Item 14.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

Unit	Condition 1	Condition 2
1	N/A	~~$118.15~~ $91.95
2	N/A	~~$1,142.88~~ $178.96
3	N/A	~~$1,169.78~~ $178.96
4	N/A	~~$5,718.60~~ $4,450.64

B. Hourly Surcharge Penalty Rate

A Unit=s Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate

6. Target Available Hours

A Unit=s Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

$$\text{Target Available Hours (TAH)} = \begin{pmatrix}\text{Hours in the}\\ \text{Calendar Year}\end{pmatrix} - \left[\begin{pmatrix}\text{Average Other}\\ \text{Outage Hours}\end{pmatrix} + \begin{pmatrix}\text{Long - Term Planned}\\ \text{Outage Hours}\end{pmatrix}\right]$$

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
1	598	0	8,162
2	~~4,356~~ 1,314	0	~~4,405~~ 7,446
3	~~3,994~~ 1,314	0	~~4,766~~ 7,446
4	1,909	2,088	4,763

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
1	~~$964,300~~ $750,490
2	~~$5,033,823~~ $1,332,556
3	~~$5,575,139~~ $1,332,556
4	~~$27,239,880~~ $21,200,113

Hunters Point Power Plant
PG&E Rate Schedule FERC No. 209
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SETTLEMENT SUBSTITUTE REVISED SHEETS

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12. **Contract Service Limits**

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups
1	20,837	851	68
2	N/A	7,446	19
3	N/A	7,446	24
4	588,611	6,545	11

Maximum Monthly MWh (Hydroelectric Units only) (N/A)

MWh

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

13. **Owner's Repair Cost Obligation**

Owner's Repair Cost Obligation for the current Contract Year is $297,473.

14. **Existing Contractual Limitations and Other Contract Restrictions on Market Transactions**

The only restriction that applies is the agreement between PG&E and the City and County of San Francisco:

In the "Agreement between the City and County of San Francisco and Pacific Gas and Electric Company to Close the Hunters Point Power Plant," signed July 9, 1998, PG&E agreed to permanently switch to the then-existing Conditions of Must-Run Agreement "C" or its substantively equivalent successor contract. Under this Must-Run Service Agreement, Condition 2 is the successor to Condition C. Pursuant to this commitment, PG&E agreed to operate the Hunters Point Power Plant only when called upon to do so by the ISO for reliability purposes.

15. **Applicable UDC Tariff(s)**

PG&E's Schedule S-Standby Service will apply for the provision of auxiliary power wherever the UDC Tariff is used for the cost of auxiliary power in these Schedules.

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

$ For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
	N/A

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

Unit	Condition 1	Condition 2
1	N/A[1]	$91.95
2	N/A	$178.96
3	N/A	$178.96
4	N/A	$4,450.64

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

[1] Hunters Point is restricted to operating as a Condition 2 Facility per the agreement between PG&E and the City and County of San Francisco noted in Schedule A, Item 14.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

Unit	Condition 1	Condition 2
1	N/A	$91.95
2	N/A	$178.96
3	N/A	$178.96
4	N/A	$4,450.64

B. Hourly Surcharge Penalty Rate

A Unit=s Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate

6. Target Available Hours

A Unit=s Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

$$\text{Target Available Hours (TAH)} = \begin{pmatrix}\text{Hours in the}\\ \text{Calendar Year}\end{pmatrix} - \left[\begin{pmatrix}\text{Average Other}\\ \text{Outage Hours}\end{pmatrix} + \begin{pmatrix}\text{Long-Term Planned}\\ \text{Outage Hours}\end{pmatrix}\right]$$

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

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Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
1	598	0	8,162
2	1,314	0	7,446
3	1,314	0	7,446
4	1,909	2,088	4,763

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
1	$750,490
2	$1,332,556
3	$1,332,556
4	$21,200,113

San Joaquin Power Plant
PG&E Rate Schedule FERC No. 211
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS

Redlines

Where:

A. Hourly Availability Charge is calculated in accordance with Equation B-4 below:

Equation B-4

Hourly Availability Charge = Hourly Availability Rate x Fixed Option Payment Factor

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

$ For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor
All	0.20

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

	Condition 1	Condition 2
All	~~$773.83~~ $756.15	N/A [1]

[1] Hydroelectric Facilities are not permitted to operate under Condition 2.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

	Condition 1	Condition 2
Unit 1	~~$2,321.48~~ $2,268.45	N/A

B. Hourly Surcharge Penalty Rate

A Unit=s Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

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Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
Kerckhoff 1	1,184	0	7,576
Kerckhoff 2	771	768	7,221
Crane Valley	682	936	7,142
San Joaquin 1A	986	936	6,838
San Joaquin 2	834	936	6,990
San Joaquin 3	660	936	7,164
AG Wishon	2,375	936	5,449
San Joaquin[2] Weighted Average	969	667	7,124

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

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Table B-6

Unit	Annual Fixed Revenue Requirement
All	~~$27,562,672~~ $26,933,123

[2] Weighted by Unit Maximum Net Dependable Capacity.

San Joaquin Power Plant
PG&E Rate Schedule FERC No. 211
2002 Annual Updates

SETTLEMENT SUBSTITUTE REVISED SHEETS

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Where:

A. Hourly Availability Charge is calculated in accordance with Equation B-4 below:

Equation B-4

Hourly Availability Charge = Hourly Availability Rate x Fixed Option Payment Factor

Where:

$ Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

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Unit	Fixed Option Payment Factor
All	0.20

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

	Condition 1	Condition 2
All	$756.15	N/A [1]

[1] Hydroelectric Facilities are not permitted to operate under Condition 2.

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

	Condition 1	Condition 2
Unit 1	$2,268.45	N/A

B. Hourly Surcharge Penalty Rate

A Unit=s Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

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Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
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Crane Valley	682	936	7,142
San Joaquin 1A	986	936	6,838
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San Joaquin 3	660	936	7,164
AG Wishon	2,375	936	5,449
San Joaquin[2] Weighted Average	969	667	7,124

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement
All	$26,933,123

[2] Weighted by Unit Maximum Net Dependable Capacity.

DRAFT COMMISSION LETTER ORDER

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

______________, 2002

In Reply Refer To:
Docket Nos. ER02-11-000 and
ER02-208-000

Pacific Gas and Electric Company
ATTN: Shiran Kochavi, Esq.
Attorney for Pacific Gas and
Electric Company
P.O. Box 7442
San Francisco, CA 94120

Dear Mr. Kochavi:

On April 19, 2002, you filed, on behalf of Pacific Gas and Electric Company ("PG&E"), an Offer of Settlement ("Offer of Settlement") in the above referenced dockets. The Offer of Settlement resolves all issues pending in these proceedings, which concern certain changes to the rates and terms of PG&E's Reliability Must-Run Agreements with the California Independent System Operator Corporation.

The subject settlement is in the public interest and is hereby approved. The rates submitted with the settlement are accepted for filing and are designated and made effective as shown on the enclosure. The Commission's approval of the settlement does not constitute approval of, or precedent regarding, any principle or issue in these proceedings. The Commission retains the right to investigate the rates, terms and conditions under the just and reasonable and not unduly discriminatory or preferential standard of Section 206 of the Federal Power Act, 16 U.S.C. § 824e.

This letter terminates Docket Nos. ER02-11-000 and ER02-208-000.

By direction of the Commission.

Magalie Roman Salas,
Secretary.

cc: All Parties

State of California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3296

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused to be served by First Class U.S. Mail, *Pacific Gas and Electric Company's the foregoing Offer of Settlement,* upon all parties designated on the official Service List compiled by the Federal Energy Regulatory Commission in this proceeding and the following:

Gary M. Cohen
General Counsel
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94103

Dated at San Francisco, California, this 18th day of April, 2002.

Joanne M. Myers

Joanne M. Myers

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street, Room 1323, B13L
San Francisco, CA 94105
(415) 973-3397